Consideration of Comments

Project 2007-06 System Protection Coordination

The System Protection Coordination Drafting Team thanks all commenters who submitted comments on draft 2 of PRC-027-1**.** The standard was posted for a 30-day public comment period from November 16, 2012 through December 17, 2012. Stakeholders were asked to provide feedback on the standard through a special electronic comment form. There were 82 sets of comments, including comments from approximately 220 different people from approximately 157 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received

Effective Dates

Based on discussion within the drafting team, the effective date was changed from "…the first day of the first calendar quarter that is six months beyond…" to "…the first day of the first calendar quarter that is 12 months beyond…" since there could be a significant number of Interconnected Elements requiring analysis due to the new requirements.

Definitions

Interconnected Element:

Based on comments related to the use of the term "Functional Entities" and the inclusion of the phrase "a Registered Entity that represents multiple functional entities", the drafting team revised the definition as follows:

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Interconnected Element: A BES Element that electrically joins facilities owned by:

a) separate Registered Entities, or

b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Protection System Coordination Study

Based on the conflict of the abbreviation of a "Protection System Study" vs. a "Power System Study", the drafting team revised the term to "Protection System Coordination Study".

Purpose

Many commenters stated that the Purpose should not include the phrase "such that the least number of power system Elements are isolated to clear Faults" or had other suggestions to improve the Purpose. The drafting team changed the Purpose to: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.

Applicability:

PRC-027-1

To add clarity, the drafting team added the following sentence to the 4.2 Facilities: For the purpose of the requirements contained herein, the following Protection Systems owned by each Functional Entity in 4.1 above are those to which these requirements are applicable.

PRC-001-3

The Applicability section was updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)

Background

General updates to reflect recent activities associated with PRC-001 and the statuses of other ongoing projects.

NERC

Requirements

The time frame for Requirement R1, Part 1.1.1 was increased to 60 calendar months to allow entities with large numbers of Interconnected Elements enough time to complete the Protection System Coordination Studies.

The drafting team modified the timeframe in Requirement R1, Part 1.1.2 to "…12 calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2…" due to the fact that with the new requirements, the possibility exists there could be a significant number of Protection System Coordination Studies required.

The drafting team modified Requirement R1, Part 1.1.3 to add a six month timeframe for the notification related to Requirement R3, Part 3.3. It now reads: "According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1, or within six calendar months of being notified of a change as described in Requirement R3, Part 3.3; or technically justify why such a study is not required."

The drafting team modified Requirement R1, Part 1.2 for clarity.

Based on comments and drafting team discussions, Requirement R2 was revised to allow a technical justification demonstrating why Fault current does not affect the Protection System coordination, and the timeframe was revised from once every 24 months to once every 60 calendar months.

Based on comments, the equation in Requirement R2, Part 2.2 was restated - "% deviation" was replaced with "% change".

The drafting team modified Requirement R2, Part 2.2.1 for clarity.

The drafting team made minor edits to Requirement R3, Part 3.1 to provide clarity.

To clarify what was expected as a response, the drafting team modified Requirement R4, Part 4.1 as follows: Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Coordination Study (per Requirement R1, Part 1.2) and respond to the other owner(s): Accepting the results, or Rejecting the results, and suggesting modifications to resolve any identified coordination issues.

To clarify what was expected by the phrase 'confirming acceptance' used in the previous draft, the drafting team changed Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues. The drafting team explained in the responses that "accepting results" only indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agree with the other entities philosophy.

Measures:
PRC-027-1

A new Measure M3 was added to account for the option of providing a technical justification for not performing a short circuit study. The other measures were renumbered and/or modified to be consistent with the revised requirements.

PRC-001-3

A new Measure M1 was added. The Measure reads as follows: For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel.

Evidence Retention

The drafting team modified the language for consistency.

VSLs

The drafting team modified the VSLs for clarity and consistency with the revised requirements.

Guidelines and Technical Basis

Complementary changes were made to the Guidelines and Technical Basis corresponding to all changes to the standard.

The drafting team updated the process flow chart to align with the revised requirements, as well as updated the Example Process.

In the introductory section for the Diagrams, the drafting team revised the language and added notes to provide clarity.

The Figures were modified to identify the Interconnected Elements, and slightly modified Figure 5 for clarity.

The drafting team revised the description relating to Figure 3 in the “Guidelines and Technical Basis” to clarify that only the Distribution Provider’s Protection Systems installed for the purpose of detecting Faults on BES Elements are a part of the Applicability of this standard.

Unresolved Minority Views
PRC-027-1

- A few commenters disagreed with the 10% deviation trigger. The drafting team recognizes there are variations of margins used throughout the industry; however, believes that the 10% margin allows notification of potential issues and corrective actions prior to reaching their typical setting margin. The drafting team did not make any of the suggested changes.

- Several commenters expressed a desire to see the standard drafting team develop and include a conflict resolution process for situations where mutual agreement cannot be reached. The drafting team responded with the following: The drafting team believes that any conflict resolution should be handled through normal business practices.

- A couple of comments indicated that Transmission Owners could not share knowledge of its system with Generator Owners and, as such, Generator Owners should not be included in the Applicability. The drafting team disagreed that Transmission information could not be shared with Generator Owners and that there is a reliability benefit in requiring each entity to ensure proper coordination exists.

- A few commenters requested that the initial study in Requirements R1 part 1.1.1 be moved to the implementation plan. The drafting team investigated this as an option but did not make this change. The drafting team stated that it believes the current structure of Requirement R1, Part 1.1.1., as currently written, achieves this same goal.

- A few commenters believed Requirement R4, Part 4.2 was unnecessary and should be eliminated. The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.

PRC-001-3

- Several commenters asked about revisions to PRC-001. The drafting team noted several things related to this:

    - The drafting team did not modify the purpose.

    - The Applicability section was updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)

    - The drafting team did add Measure M1, which reads: "For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel."

    - The drafting team recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	1
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
9.	Donald Weaver	New Brunswick System Operator	NPCC, NPCC	2
10.	David Kiguel	Hydro One Networks Inc.	NPCC, NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC, NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC, NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC, NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC, NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC, NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC, NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC, NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC, NPCC	5
19.	Brian Robinson	Utility Services	NPCC, NPCC	8
20.	Ben Wu	Orange and Rockland Utilities	NPCC, NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC, NPCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Co.	RFC	1, 3
2.	Alvin Depew	Pepco Holdings Inc	RFC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Steve Alexanderson P.E.	Western Small Entity Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russ Schneider	Flathead Electric	WECC	3, 4
2.	Russell A. Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
3.	Rick Paschall	Blachly-Lane Electric Cooperative	WECC	3
4.	Rick Paschall	Central Electric Cooperative	WECC	3
5.	Rick Paschall	Consumers Power	WECC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Rick Paschall	Clearwater Power Company	WECC 3										
7.	Rick Paschall	Douglas Electric Cooperative	WECC 3										
8.	Rick Paschall	Fall River Rural Electric Cooperative	WECC 3										
9.	Rick Paschall	Northern Lights	WECC 3										
10.	Rick Paschall	Lane Electric Cooperative	WECC 3										
11.	Rick Paschall	Lincoln Electric Cooperative	WECC 3										
12.	Rick Paschall	Raft River Rural Electric Cooperative	WECC 3										
13.	Rick Paschall	Lost River Electric Cooperative Lost River Electric Cooperative	WECC 3										
14.	Rick Paschall	Salmon River Electric Cooperative	WECC 3										
15.	Rick Paschall	Umatilla Electric Cooperative	WECC 1, 3										
16.	Rick Paschall	Coos-Curry Electric Cooperative	WECC 3										
17.	Rick Paschall	West Oregon Electric Cooperative 4	WECC 3										
18.	Rick Paschall	Pacific Northwest Generating Cooperative	WECC 3, 4, 8										
19.	Rick Paschall	Power Resources Cooperative	WECC 6										
4.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				
5.	Group	Joseph DePoorter	Midwest Reliability Organization NERC Standards Review Forum	X	X	X	X	X	X				

Group 4 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6

Group 5 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Breene	WPS	MRO	3, 4, 5, 6
4.	Jodi Jenson	WAPA	MRO	1, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Alice Ireland	XCEL (NSP)	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6
9.	Joseph DePoorter	MGE	MRO	3, 4, 5, 6
10.	Scott Nickels	RPU	MRO	4

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11. Terry Harbour	MEC	MRO	1, 3, 6
12. Marie Knox	MISO	MRO	2
13. Lee Kittelson	OTP	MRO	1, 3, 5, 6
14. Scott Bos	MPW	MRO	1, 3, 5, 6
15. Tony Eddleman	NPPD	MRO	1, 3, 5
16. Mike Brytowski	GRE	MRO	1, 3, 5, 6
17. Dan Inman	MPC	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jonathan Hayes	Southwest Power Pool	SPP	NA
2. Robert Rhodes	Southwest Power Pool	SPP	NA
3. Greg Froehling	Rayburn Electric		NA
4. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
5. Valerie Pinnamonti	American Electric Power	SPP	1, 3, 5
6. Clem Cassmeyer	Western Farmers	SPP	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
7.	Group	Michael Jones	National Grid and Niagara Mohawk (A National Grid Company)	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Michael Schiavone	Niagara Mohawk (A National Grid Company)	NPCC	3

				1	2	3	4	5	6	7	8	9	10
8.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dean Bender	SPC Technical Svcs	WECC	1
2. Deanna Phillips	FERC Compliance	WECC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
9.	Group	Mary Jo Cooper	GP Strategies	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Elizabeth Kirkley	City of Lodi	WECC	3
2. Colin Murphey	City of Ukiah	WECC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
3. Douglas Draeger	Alameda Municipal Power	WECC	3
4. Angela Kimmey	Pasadena Water and Power	WECC	1, 3
5. Blaine Ladd	California Pacific Electric Company	WECC	3
6. Ken Dize	Salmon River Electric Co-op	WECC	3
7. Michael Knott	Granite State Electric	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Brenda Hampton	Luminant						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Rick Terrill	Luminant Generation Company LLC	ERCOT	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Louis Slade	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Steve Edwards	Electric Transmission	SERC	1, 3
2. Sean Iseminger	Fossil & Hydro	SERC	5
3. Chip Humphrey	Fossil & Hydro	NPCC	5
4. Connie Lowe	NERC Compliance Policy	RFC	5, 6
5. Jeff Bailey	Nuclear	NPCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	David Greene	SERC Protection and Controls Subcommittee (PCS										X

Additional Member	Additional Organization	Region	Segment Selection
1. Bridget Coffman	Santee Cooper	SERC	
2. Steve Edwards	Dominion, Virginia Power	SERC	
3. Ernesto Paon	MEAG Power	SERC	
4. Greg Davis	Georgia Transmission	SERC	
5. James Evans	SCANA	SERC	
6. Paul Nauert	Ameren	SERC	
7. George Pitts	TVA	SERC	
8. David Greene	SERC	SERC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Ben Engelby	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

1.	John Shaver	Arizona Electric Power Cooperative Inc. and Southwest Transmission Cooperative Inc.	WECC	1, 4, 5
2.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
3.	William Hutchison	Southern Illinois Power Cooperative	SERC	1
4.	Chris Bradley	Big Rivers Electric Corporation	SERC	
5.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
6.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
7.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
8.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
9.	Amber Anderson	East Kentucky Power Cooperative	SERC	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Sasa Maljukan	Hydro One Networks Inc.	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Difilippo	Hydro One Networks Inc.	NPCC	1
2.	David Kiguel	Hydro One Networks Inc.	NPCC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	make haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Service	FRCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Group	Charles Yeung	Certain Members of the ISO RTO Council		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Campoli	NYISO	NPCC	2
2.	Ali Miremadi	CAISO	WECC	2
3.	Bill Phillips	MISO	RFC	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Ben Li	IESO	NPCC	2

				1	2	3	4	5	6	7	8	9	10
18.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Detweiler	FirstEnergy	RFC	1, 3, 4
2.	Bill Duge	FirstEnergy	RFC	5
3.	Robert Loy	FirstEnergy	RFC	5
4.	Brian Orians	FirstEnergy	RFC	5
5.	Larry Raczkowski	FirstEnergy	RFC	1, 3, 4, 5, 6

				1	2	3	4	5	6	7	8	9	10
19.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6
5.	Daniel McNeely		SERC	1

				1	2	3	4	5	6	7	8	9	10
20.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

				1	2	3	4	5	6	7	8	9	10
21.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

				1	2	3	4	5	6	7	8	9	10
22.	Group	Thomas McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

				1	2	3	4	5	6	7	8	9	10
23.	Individual	Joe Uchiyama	US Bureau of Reclamation	X				X				X	
24.	Individual	Rowell Crisostomo	ATCO Electric	X									
25.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
26.	Individual	Janet Smith	Arizona Public Service Company	X		X	X	X	X	X			
27.	Individual	Ed Croft	Operational Compliance	X		X		X					
28.	Individual	ryan millard	pacificorp	X		X	X	X					
29.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
30.	Individual	Antonio Grayson	Southern Company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
31.	Individual	Jim Watson	Dynegy					X					
32.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
33.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					
34.	Individual	Andrew Z. Pusztai	American Transmssion Company, LLC	X									
35.	Individual	Si Truc PHAn	Hydro-Quebec TransEnergie	X									
36.	Individual	NICOLE BUCKMAN	ATLANTIC CITY ELECTRIC COMPANY			X							
37.	Individual	Don Jones	Texas Reliablity Entity										X
38.	Individual	Patrick Brown	Essential Power, LLC					X					
39.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
40.	Individual	Mark Yerger	Potomac Electric Power Compan			X							
41.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
42.	Individual	Scott Miller	MEAG Power	X									
43.	Individual	Wryan Feil	Northeast Utilities	X		X		X					
44.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
45.	Individual	Thad Ness	American Electric Power	X		X		X	X				
46.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
47.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
48.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
49.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
50.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
51.	Individual	David Jendras	Ameren	X		X		X	X				
52.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
53.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
54.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
55.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
56.	Individual	Jim Howard	Lakeland Electric	X		X		X	X				
57.	Individual	Larry Watt	Lakeland Electric	X		X		X	X				
58.	Individual	Michael Moltane	ITC	X									
59.	Individual	Michael Falvo	Independent Electricity System Operator		X								
60.	Individual	Anthony Jablonski	ReliabilityFirst										X
61.	Individual	Jonathan Meyer	Idaho Power Co.	X									
62.	Individual	Brian Murphy	NextEra Energy	X		X		X	X				
63.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
64.	Individual	Saul Rojas	New York Power Authority	X		X		X	X			X	
65.	Individual	Stephanie Monzon	PJM Interconnection		X								
66.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
67.	Individual	Richard Vine	California Independent System Operator	X	X	X	X	X	X				
68.	Individual	John Bee	Exelon Corporation and its affiliates										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
69.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
70.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X					
71.	Individual	Marie Knox	MISO		X								
72.	Individual	Jim Cyrulewski	JDRJC Associates								X		
73.	Individual	Clay Young	SCE&G	X		X		X	X				
74.	Individual	Daniela Hammons	CenterPoint Energy	X									
75.	Individual	Greg Davis	Georgia Transmission Corporation	X									
76.	Individual	Scott McGough	Georgia System Operations Corporaton			X							
77.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
78.	Individual	Angela P Gaines	Portland General Electric Co	X		X		X	X				
79.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
80.	Individual	Karen Webb	City of Tallahassee	X		X		X					
81.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
82.	Individual	Rich Salgo	NV Energy	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
Illinois Municipal Electric Agency	Florida Municipal Electric Agency
Hydro-Quebec TransEnergie	NPCC
ATLANTIC CITY ELECTRIC COMPANY	Pepco Holdings Inc and Affiliates
Delmarva Power & Light Company	Potomac Electric Power Company, Transmission Owner (Segment 1)
Potomac Electric Power Compan	Pepco Holdings Inc and Affiliate
MEAG Power	Essential Power, LLC
Northeast Utilities	Northeast Power Coordinating Council Inc. (NPCC)1040 Avenue of the Americas10th FloorNew York, NY 10018
Consolidated Edison Co. of NY, Inc.	NPCC, the Northeast Power Coordinating Council
Flathead Electric Cooperative, Inc.	Support both the previous comments of Bonneville Power Administration and the comments of the Western Small Entity Comment Group

Organization	Supporting Comments of “Entity Name”
Lincoln Electric System	MRO NSRF
The United Illuminating Company	Northeast Power Coordinating Council (NPCC)
Lakeland Electric	FMPA
Lakeland Electric	Please see FMPA comments.
New York Power Authority	NPCC
California Independent System Operator	The California ISO is in support of, and has signed on with, the comments submitted by the Standards Review Committee (SRC) (ISO/RTO Council).
MISO	MISO supports the comments submitted by the Standards Review Committee (SRC).
JDRJC Associates	Midwest ISO
Georgia System Operations Corporaton	Georgia Transmission Corporation
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing

1. **Based on stakeholder comments, the drafting team modified the Purpose of this standard to "To coordinate Protection Systems for Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults." Do you agree with this Purpose? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Many commenters stated that the purpose should not include the phrase "such that the least number of power system Elements are isolated to clear Faults" or had other suggestions to improve the Purpose. The drafting team revised the Purpose to read: "To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults."

Some commenters stated that the definition of "Interconnected Element" needed to be changed. The drafting team changed the definition to:

A BES Element that electrically joins facilities owned by:
a) separate Registered Entities, or
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Some commenters noted that a Transmission Owner could not share knowledge of its system with Generator Owners, as such; Generator Owners should not be included in the Applicability. The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated.

Others commenters believed that the Generator Owner should be excluded because the Transmission Owner is the entity that maintains that Transmission System Fault studies. While the drafting team agrees that Transmission Owners usually maintain the Fault studies, it believes that both entities have a responsibility to ensure the Protection Systems covered by this standard are properly coordinated.

A commenter believed that the Purpose of PRC-001-3 should be changed. The drafting team did not modify the Purpose, but did add Measure M1. It reads: "For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel."

A few commenters requested more clarity on which Protection System are included in the standard. The drafting team explained that because of differing philosophies among entities, it could not specify all Protection Systems that may require coordination. The drafting team believes the Applicability section gives sufficient guidance.

A commenter indicated that "coordination" is not well-defined. Rather than trying to develop a definition in the NERC Glossary of Terms, the drafting team chose to express what was intended for "coordination" in this standard.

There was a concern that the standard might be expanding into Distribution Elements. The drafting team explained that the Applicability only applies to Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on BES Elements and that require coordination for isolating those Faulted Elements."

A commenter disagreed with the need to periodically review coordination. The drafting team indicated that it believes there is a reliability benefit in periodically reviewing Protection System coordination.

One comment indicated that the Figures needed more explanation regarding which were the "Interconnected Elements." The drafting team modified the figures to indicate the "Interconnected Elements."

One commenter stated that there was a lack of consistency between the Purpose and Requirement 1, Part 1.2. The drafting team revised the language of both to remove any inconsistencies.

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	No	It seems the real purpose of this standard is "To coordinate BES Protection Systems for Interconnected Elements". The rest of the statement is already covered as part of the protection systems design which will involve coordination or not depending on any special issues or existing design limits.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults		
ACES Standards Collaborators	No	(1) We disagree with the inclusion of the "least number of power system Elements" in the purpose. The purpose should be to simply coordinate the Protection Systems for Interconnected Elements. While trying to minimize the number of Elements that should be removed from service is a laudable goal, it will create an incentive for auditors to determine if there is a better way to protect the registered entities systems. How else could an auditor know that the absolute minimum of Elements have been determined unless they tried optimize the zone of protection themselves. The use of different but related terms causes confusion. For instance, what is the difference among "power system Elements," "Elements," and "Interconnected Elements"? Based on the definition of "Element," we assume "power system Elements" is intended to be the same. If so, we suggest dropping "power system" to avoid confusion. (2) Similar to the purpose statement, the Applicability Section, (4.2) Facilities is unclear. The statement "Interconnected Elements of the BES that require coordination for isolating those faulted Elements" includes superfluous language. In general, NERC enforces standards against the BES. Thus, it is not necessary to include "of the BES." To ensure absolute clarity, we suggest the definition of Interconnected Element be modified to specifically limit it to the BES as well. Also, we recommend striking everything after Interconnected Elements in the purpose statement as it is unnecessary and provides no additional clarification on the Facilities to which the standard applies. (3) Because no generic questions asking for additional comments was provided, we are providing our concerns that do not fall under one of the specific questions asked of the drafting team here. (4) Please change the wording of Part 1.2 as the current wording has some

Organization	Yes or No	Question 1 Comment
		unintended consequences. We think “to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement” should be changed to “to the other owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of the associated Protection System Study.” The current language literally reads that the TO, GO, and DP shall provide the PSS results to itself. It also reads that all the Protection System Studies for a TO, GO, or DP must be provided to the other protection system owners of all of the Interconnected Elements even if the other owners only own protection systems for one of the TO, GO, or DP’s Interconnected Elements. As an example, consider that TO X shares two separate Interconnected Elements with TO Z and GO A. The Interconnected Element between TO X and TO Z is called Tie-line B and the Interconnected Element between TO X and GO A is GSU C. The requirement would literally require TO X to share its Protection System Study results for both Tie-line B and GSU C with both GO A and TO Z even though, GO A has no interest in Tie-Line B and TO Z has no interest in GSU C. This could be solved with the simple edit described above. (5) We find that addition of “For each Facility associated with an Interconnected Element on its System” in R2 confusing. First, what is an associated Facility? Second what is intended by the use of Facility instead of Element? Considering Interconnected Facility in the last draft was change to Interconnected Element and Facility was used in this requirement, it would appear some delineation is meaning is intended between Element and Facility. Since Element and Facility have nearly the same meaning in the NERC Glossary of Terms that delineation is unclear and we would appreciate further explanation of the intent. (6) We found the inclusion of quotes on the phrase “Protection Systems installed to detect faults on the BES Transmission System” confusing. There is no reference. We suggest removing the quotes as they are superfluous. The meaning is still communicated without them. If they remain, please provide a

Organization	Yes or No	Question 1 Comment
		reference. We assumed it came from section 4.2. If the quote did come from that section, it is not quite correct. It is missing "for the purpose of detecting" and "faults" is not capitalized (7) The purpose statement of PRC-001-3 needs to be further modified. With the deletion of all of the requirements but Requirement R1, the purpose to "ensure system protection is coordinated among operating entities" is no longer achieved.

Response: Thank you for your comments.

1. **The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.**
2. **The definition of Interconnected Element has been revised based on your and others' comments to read:**
   A BES Element that electrically joins facilities owned by:
   a) separate Registered Entities, or
   b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).
3. **NA**
4. **The suggested change has been made**
5. **The language in Requirement R2 has been clarified**
6. **The phrase you mentioned has been modified to accurately reflect the language in the Figure from which it was taken.**
7. **The large majority of the Standard is a carryover from the standards PRC-001-1 and PRC-001-2. As noted in the background section of PRC-027-1, the drafting team is recommending that Requirement R1 only remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. At that time PRC-001-3 will be retired.**

Organization	Yes or No	Question 1 Comment
Certain Members of the ISO RTO Council	No	Although the SRC agrees that protection systems should strive to interrupt only those elements closest in to a fault to avoid excessive interruptions, there are situations where it is necessary to trip elements beyond those that only interrupt the fault. To set a result for "...the least number of power system Elements are isolated to clear Faults" misses the primary goal for a reliability

Organization	Yes or No	Question 1 Comment
		standard meant to protect the interconnected bulk electric grid. NERC standards should always have the underlying purpose to prevent cascading failures that affect interconnected systems. The stated Purpose must recognize that the "least number of power system Elements are isolated to clear Faults to maintain system integrity". For example, a relay scheme could isolate a fault on a generator connected between two line terminals by opening the breakers on both ends of the line. This would fulfill the Purpose of "least number of power system Elements", however, a protections scheme for that segment of transmission line may require that the next terminal along that line also be interrupted in order to prevent an unintended increase in load to a particular element due to the opening of the breakers closest to the fault.
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Northeast Power Coordinating Council	No	1. By restricting the coverage to "... Interconnected Elements, such that the least number of power system Elements are isolated to clear Faults" there is a significant gap in reliability created by the exclusion of elements such as loss of field, out-of-step, etc. 2. An incomplete Protection System Study negates all the work needed to satisfy this Standard. Perhaps through referencing the NERC technical reference document entitled "Power Plant and Transmission Protection Coordination", there could be a reference to which protection elements are going to be covered in this Standard and likewise what Standards will cover the protection elements not covered by this Standard. 3. As identified by the Drafting Team, there may be no evidence of mis-coordination between traditional protections that detect faults, but for co-ordination of generator loss of excitation protection settings or out of step relaying during a fault condition - is that meant to be covered in this Standard

Organization	Yes or No	Question 1 Comment
		or elsewhere? 4. The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions, not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even provided options on how to mitigate those elements. PRC-027 should provide the similar effective vehicle to convey at least the "what" for Protection System coordination during faults between entities, and will allow entities to perform and document consistent Protection System Studies. 5. The term "coordination" is not well defined. Does it mean ensuring owners of all terminals of a line, transformer, etc. are aware of each other's protection system design and settings, especially when the design, settings, and physical system changes? Developing a formal definition to be included in the NERC Glossary should be considered.
Response: Thank you for your comments. 1. **The coordination of non-fault-related Protection Systems such as what you describe is not within the scope of this standard.** 2. **Because there are different Protection System designs and philosophies, the drafting team cannot specify which Protection Systems require coordination.** 3. **The drafting team believes that conditions such as those that you suggested are expected to be remedied under other standards. For example, out-of-step conditions should be identified and mitigation coordinated and implemented as a result of a transmission system assessment required in the TPL standards.** 4. **The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.** 5. **The drafting team agrees that "coordination" is not well-defined. Rather than trying to develop a definition in the NERC Glossary of Terms, the drafting team chose to express what was intended for coordination in this standard.**		
CenterPoint Energy	No	CenterPoint Energy believes the purpose should use wording similar to that being proposed for the definition of "Protection System Study" instead of developing and utilizing different wording for the purpose statement.

Organization	Yes or No	Question 1 Comment
		CenterPoint Energy recommends the purpose be stated as follows: "To coordinate Protection Systems for Interconnected Elements, such that Protection Systems operate as desired for clearing postulated short circuit Fault events."
Response: Thank you for your comment. The Purpose has been revised read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
NV Energy	No	Concerned that the Applicability and Purpose are encroaching upon Distribution elements, outside the statutory authority of the NERC Standards process
Response: Thank you for your comment. Per the Applicability, the standard applies only to Distribution Providers that own "Protection Systems installed for the purpose of detecting Faults on BES Elements and that require coordination for isolating those faulted Elements." This standard does not pertain to distribution (non-BES) Elements.		
Exelon Corporation and its affiliates	No	Exelon agrees with the Purpose statement as stated, however the questions and layout of this comment form doesn't provide an area to provide comments as to why we are voting negative. While requiring periodic coordination studies between entities is laudable, it is unnecessary. The coordination of a protection system, by nature, is tested every time it operates. We already have a standard, PRC-004-2, that requires all transmission protection system operations to be analyzed for correctness and any misoperations reported, along with corrective action plans to mitigate their cause. Our experience indicates the bulk of protection system misoperations are not caused by a lack of coordination studies. This standard, as written, continues to be vague and will lead to an inconsistent application of the requirements. Most importantly, we believe this standard is ill advised. Coordination of protection systems between entities was not a factor in the 2003 blackout. As such it clearly goes beyond the mandate of the 2003 blackout recommendations. Implementation of this standard will add little to the reliability of the bulk electric system while adding substantially to the amount of time and money an entity spends simply on compliance

Organization	Yes or No	Question 1 Comment
		activities. Contrary to the goal of enhancing reliability, this standard will simply dilute available resources to the detriment of reliability.
Response: Thank you for your comment. The drafting team believes there is a reliability benefit to review and ensure proper Protection System coordination on existing Protection Systems associated with Interconnected Elements prior to potentially being identified by a misoperation. The aspects of coordination included in the existing Reliability Standard PRC-001-2 are incorporated and clarified in the proposed Reliability Standard PRC-027-1.		
FirstEnergy	No	In regard to the purpose statement, FirstEnergy supports the response submitted by the RFC Protection Subcommittee which is repeated here for convenience. The purpose should mirror the objectives of the Protection Systems Study. “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence.” The reasons being that an entity may choose to overtrip distribution transformer (non-BES) protection, to employ zone 1 extension schemes, or for other valid reasons trip more than the least number of Elements to clear a Fault.
Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Pepco Holdings Inc & Affiliates	No	The language in the Statement of Purpose needs to be reworded. The phrase “such that the least number of power system Elements are isolated to clear faults” may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into

Organization	Yes or No	Question 1 Comment
		(but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a fault on the line, it would violate the requirement that “the least number of power system Elements are isolated to clear faults”. The language used in the proposed definition of Protection System Study is better; using the phrase “demonstrates ... Protection Systems operate in the desired sequence for clearing faults”. The problem here is who determines what is the “desired sequence”? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the “desired sequence” for clearing faults? The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point. In conclusion, we suggest re-wording the Purpose to read: “To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence for clearing Faults.” This statement is consistent with the stated definition of the Protection System Study, on which the measures of this standard are based.

Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired

Organization	Yes or No	Question 1 Comment
sequence during Faults.		
Florida Municipal Power Agency	No	The primary purpose of protection system coordination is to ensure faults are cleared expeditiously and well under the critical clearing time, with the stated purpose of minimizing the number of elements isolated as a secondary consideration, not a primary consideration. As such, there is no recognition of the importance of remote back-up protection that backs up primary and secondary protection, but, does not necessarily share the same goal of minimizing number of elements tripped, but, does share the goal of clearing a fault within the critical clearing time.
Response: Thank you for your comment. The drafting team agrees with your statement that critical clearing time is important. The drafting team revised the Purpose: however, the team believes that minimizing the elements isolated is simply a part of accomplishing that clearing time. The coordination between the primary and backup protection that you address has to take place, otherwise there would always be isolation of more than is necessary to clear the Faults.		
Bonneville Power Administration	No	The Purpose given assumes that the most important outcome of a protection system operation is that the least number of power system elements are isolated to clear a fault. While it is true that it is usually desirable to prevent parallel paths from opening, in many cases it might be perfectly acceptable for adjacent elements to operate. BPA believes it may be more economical to have a protection system that isolates elements in addition to the faulted element if the isolation of the additional elements does not result in problems for the BES. A suggested Purpose statement that takes this philosophy into account is: To insure that separate Functional Entities properly coordinate with each other the protective systems for elements that interconnect their electrical systems so that only the intended power system elements will be isolated to clear a fault.
Response: Thank you for your comment. The Purpose has been revised read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		

Organization	Yes or No	Question 1 Comment
Essential Power, LLC	No	The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, “the entity performing the Protection System Study [for R1],” but the standard provides no indication of who this should be. This responsibility is simply assigned to, “Each Transmission Owner, Generation Owner, and Distribution provider.” The obligation placed on GOs by use of the word “each” in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO’s system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO’s equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don’t matter to a GO. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should say so, rather than pulling in all GOs regardless of whether or not it makes any sense for them to be involved. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.

Response: Thank you for your comment. The drafting team does not believe that the Transmission Owner is restricted in providing

Organization	Yes or No	Question 1 Comment
the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated.		
Cogentrix Energy Power Management, LLC	No	The purpose is laudable, but the means by which it is to be achieved needs more work. The Application Guidelines section of PRC-027 makes reference to, “the entity performing the Protection System Study [for R1],” but the standard provides no indication of who this should be. This responsibility is simply assigned to, “Each Transmission Owner, Generation Owner, and Distribution provider.” The obligation placed on GOs by use of the word “each” in R1 cannot be fulfilled, however, except under the circumstance of having a vertically-integrated utility. An independent GO does not have knowledge of the TO’s system, and in a deregulated market is not allowed to have such knowledge. The TO and TOP are provided with detailed information of the GO’s equipment, however, and therefore perform all interconnection-related studies. This is as it should be, because changes in the transission don’t matter to a GO. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO’s system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e. reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should address that specifically. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performend by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.

Organization	Yes or No	Question 1 Comment
Response: Response: Thank you for your comment. The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated.		
PPL Corporation NERC Registered Affiliates	No	1. The purpose of this study should be "To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the proper sequence." The least number of Elements to clear a Fault may not always be the case for some Protection Systems. 2. The TO and TOP are provided with detailed information of the GO's equipment and therefore perform all interconnection-related studies. Independent generators do not modify Protection Systems in response to changes to the Fault current at an interconnecting bus, generators just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Equipment involving sequencing the tripping of multiple Elements is in the TO's system. The best approach would be to restrict the applicability of PRC-027 in its entirety exclusively to TOs, with GO obligations remaining as per PRC-001, i.e., reporting changes and addressing any issues raised by the TOP. If GOs that own substations, distribution systems and numerous miles of transmission conductors (e.g. large-scale wind farms) need to be included in PRC-027 the standard should specifically address those GOs, rather than pulling in all GOs. The most that could reasonably be asked of independent GOs under R1 is to have a valid interconnection service agreement (ISA), since a coordination study is performed by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so a detailed level of evidence could not be asked of the GO.
Response: Thank you for your comment. **1. The Purpose has been revised to read: To coordinate Protection Systems for Interconnected Elements, such that Protection**		

Organization	Yes or No	Question 1 Comment
System components operate in the desired sequence during Faults. 2. The drafting team believes that although the Transmission Owner may provide the majority of the data and work associated with this standard, the Generator Owner shares the responsibility of ensuring the Protection Systems covered by this standard are properly coordinated.		
Wisconsin Electric Power Company	No	The purpose should mirror the objectives of the Protection System Study: "To coordinate Protection Systems for Interconnected Elements, such that the Protection Systems operate in the desired sequence." There are cases where industry practice is to "overtrip", for example, for a tapped non-BES distribution transformer fault by tripping BES line breakers and reclosing. Also it may be a common practice to use zone 1 extension or acceleration schemes. There can be good reasons for intentionally tripping more than "the least number of Elements to clear a Fault". The Purpose statement as currently written is in conflict with these valid industry practices, and needs to be modified.
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Kansas City Power & Light	No	1. The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities. This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. 2. The purpose in the draft standard makes it appear that you are in violation of this standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used, but the measures tend to measure agreement with

Organization	Yes or No	Question 1 Comment
		the other entity. PRC-004 is the standard for misoperation reporting and misoperation mitigation.
Response: Thank you for your comment. 1. **The drafting team does not see a conflict between the language in the standard and your statement "This standard only requires documentation that neighboring owners are talking and agreeing with one another in relation to protection and control." The measures provide examples of documentation that demonstrate compliance with the requirements.** 2. **A Misoperation is not a violation of PRC-027-1.**		
US Bureau of Reclamation	Yes	1) We agree to isolate the least number of power system elments during a fault. However, PRC-027 & PRC-001 are lack of a statement which elements be reviewed by entities. It seems like it is upto utilities to decide wchich elements to be reviewed and studied for. For the comliance purpose, how does Autority judge the reviews/documents were meeting PRC-027? 2) Pg. 2- Definitions of Terms Used in Standard- "Interconnected Element: An Element that electrically joins separate Functional Entities, includingthose Functional Entities that are a part of the same Registered Entity." -The Interconnected Element definition should be expanded upon and attached figures added showing what is and is not an interconnected element relative to the generator and generation owner. 3) Page 2 - The term "Functional Entities" as used in the definitions for "Interconnected Element" should include a definition. 4) Pg. 4- A.5 -"Other Aspects of coordination of Protection Systems addressed by other Projects: Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1. Other items, 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 existing standards or current projects." -The paragraph should be more specific as to whether the "fault clearing" referenced is used for primary

Organization	Yes or No	Question 1 Comment
		transmission line protection or primary generator/generator step-up transformer protection. Namely, does what is addressed in PRC-027-1 exclude fault clearing used for primary generator/generator step-up transformer protection? 5) Pg. 8- R3.- 3.1- " o New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios."- The sentence should be changed to read- " o New installation, replacement with different types, or modification of: fault clearing protective relays or protective function settings, related communication systems, related current transformer ratios and voltage transformer ratios." 6) Last paragraph on page 26 starting with "Protection Systems installed to detect faults on the BES..." has some great examples (especially the last sentence of that paragraph) of the intent of PRC-027. I think it would be useful to move or copy this type of verbiage to the beginning of the document and use it in the definitions to accomplish what Pete has commented on below.

Response: Thank you for your comments

1. **The drafting team believes that the "elements be reviewed by entities" are clearly identified in the definitions and Applicability sections.**
2. **The figures have been modified to indicate the "Interconnected Element'.**
3. **The definition of Interconnected Element has been changed to: A BES Element that electrically joins facilities owned by:**
   a) separate Registered Entities, or
   b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).
4. **This standard does include those aspects of "primary generator/generator step-up transformer protection" which may require coordination with other owners. An example would be back-up distance protection or ground overcurrent protection.**
5. **The drafting team believes the definition of Protection Systems (NERC Glossary of Terms) provides adequate clarity with regards to these components. The drafting team therefore declines to incorporate your suggested changes.**

Organization	Yes or No	Question 1 Comment
6. The drafting team declines to make the suggested change.		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 1, we have the following general comment: The purpose statement and R1.2 refers to Elements within the 'power system' which is not defined, while the 'Facilities' refers to 'Elements of the BES' and the 'Requirements' reference Interconnected Element on a particular entities' 'System' or 'transmission system'. Should these be consistent or has this been done purposefully?
Response: Thank you for your comments. The drafting team modified the language to make it consistent.		
SERC Protection and Controls Subcommittee (PCS	Yes	Based on the SDT response to our Draft 1 comment regarding the use of 'coordination', we understand 'coordination' in the Title and Purpose to mean the technical aspect of relay coordination.
Response: Thank you for your comments. The drafting team agrees with your statement.		
Georgia Transmission Corporation	Yes	Based on the SDT response to our Draft 1 comment regarding the use of 'coordination', we understand 'coordination' in the Title and Purpose to mean the technical aspect of relay coordination.
Response: Thank you for your comments. The drafting team agrees with your statement.		
Dominion	Yes	1). Dominion appreciates the SDT's agreement that in PRC 001 there were different interpretations of the term "coordination. Based on the SDT response to our Draft 1 comment regarding "coordination", we now understand that 'coordination' in PRC 027 Title and Purpose is referring to the technical aspects of coordinating relay settings. 2). Please reconsider Dominion previous recommendations to change the Title. "Protection System Interconnected Element Coordination for Performance

Organization	Yes or No	Question 1 Comment
		During Faults" or "Protection System Coordination for Interconnected Elements" have more specificity and meaning to the standards intent for coordinating relays on interconnections.
Response: Thank you for your comments. **1. The drafting team agrees with your statement.** **2. The drafting team declines to make the suggested change.**		
American Transmssion Company, LLC	Yes	However, ATC recommends that the Purpose statement in the Standard be modified by adding the word "intended" :"To coordinate Protection Systems for Interconnected Elements, such that the least number of intended power system Elements are isolated to clear Faults."
Response: The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration agrees that it is appropriate that PRC-027-1 is self-contained throughout. Even though the Purpose statement is not necessarily mandatory and effective, it is conceivable that the previous version would lead a Compliance Enforcement Authority to require evidence that fault studies account for relay performance governed by other NERC standards. This could result in the assessment of two penalties for the same violation - a double jeopardy condition that should be avoided.
Response: Thank you for your support. The Purpose has been revised to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Duke Energy	Yes	The Purpose statement could be improved by striking the phrase "least number of power system Elements are isolated to clear Faults", and inserting the following phrase from the definition of Protection System Study: "Protection Systems operate in the desired sequence for clearing Faults". Some entities

Organization	Yes or No	Question 1 Comment
		may choose to "over-trip" for certain Faults.
Response: Thank you for your comment. The Purpose has been revised based on your and others' comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		
Independent Electricity System Operator	Yes	We agree with the purpose statement, but suggest to add "settings" after protection system (with the "s" removed") to make it clear that it is the coordination of the settings, not the design of protection systems.
Response: Thank you for your comment. The drafting team believes that 'settings' are not the only aspect of Protection Systems that can impact the stated purpose.		
Hydro One Networks Inc.	Yes	We agree with this Purpose statement and we commend the drafting team for moving this standard in the right direction. 1. However, in line with our previous comments from the first posting, there still seems to be a significant gap in reliability by not identifying what elements of the Protection System need to be co-ordinated between entities. Perhaps this can even reside in the Application Guide. 2. A poor or incomplete Protection System Study is worthless and negates all the work needed to satisfy this standard. 3. As identified by the drafting team, there may be no evidence of mis-coordination between traditional protections that detect faults, but for co-ordination of say generator loss of excitation protection settings or out of step relaying during a fault condition - is that meant to be covered in this standard or elsewhere? 4. The latest draft of PRC-019-1 indicates studies conducted under that standard are for steady state conditions - not fault conditions. PRC-023 provided clear direction on what protection elements to mitigate and even

Organization	Yes or No	Question 1 Comment
		provided options on how to mitigate those elements. We feel PRC-027 is an effective vehicle to convey at least the "what" for Protection System co-ordination during faults between entities and will allow entities to perform and document consistent Protection System Studies.
Response: Thank you for your comments and support. **1. Because there are different Protection System designs and philosophies, the drafting team cannot specify which Protection Systems require coordination.** **2. The drafting team agrees with your comment.** **3. The drafting team believes that conditions such as those that you suggested are expected to be remedied under other standards. For example, out-of-step conditions should be identified and mitigation coordinated and implemented as a result of a transmission system assessment required in the TPL standards.** **4. The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.**		
Ameren	Yes	We are voting negative for three reasons, one provided below and two are included in response to Question #3. Ameren also supports the SERC Protection & Control Subcommittee (PCS) comments and hereby includes them by reference rather than repeating them all. (1) We request that the SDT replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places where it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry.
Response: Thank you for your comment. The drafting team used the term 'detect Faults on the BES Transmission System' to indicate those Protection Systems that may require review with other owners Protection Systems. The drafting team revised the phrase to read "installed for the purpose of detecting Faults on BES Elements" for consistency with the Facilities section of the Applicability. It is also noted that the identified interpretation was for the term 'transmission Protection Systems' which is not used in this Standard.		

Organization	Yes or No	Question 1 Comment
Western Small Entity Comment Group	Yes	
Imperial Irrigation District (IID)	Yes	
Midwest Reliability Organization NERC Standards Review Forum	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
National Grid and Niagara Mohawk (A National Grid Company)	Yes	
GP Strategies	Yes	
Luminant	Yes	
seattle city light	Yes	
Tennessee Valley Authority	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
pacificorp	Yes	
Southern Company	Yes	
Dynegy	Yes	
Texas Reliablity Entity	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
Tacoma Power	Yes	
Entergy Services, Inc. (Transmission)	Yes	
City of Austin dba Austin Energy	Yes	
ITC	Yes	
Idaho Power Co.	Yes	
Sacramento Municipal Utility District	Yes	
Xcel Energy	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Thank you for your support.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did

Organization	Yes or No	Question 1 Comment
revise some of the VSLs.		
Western Electricity Coordinating Council		We agree that unnecessary power system Elements should not be isolated to clear Faults, but question the statement that the “least number of power system Elements should be isolated.” Reliability should be the goal. There may be situation where different isolation schemes both work, but perhaps one that isolates one or two more elements is more reliable.
Response: Response: Thank you for your comment. The Purpose has been revised based on your and others’ comments to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.		

2. The drafting team is proposing two definitions for use only with PRC-027-1 as follows: Interconnected Element: An Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity Protection System Study: A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Do you agree with these definitions, if not please provide specific suggestions for change in the comment area.

Summary Consideration:

Interconnected Element

The following two items represent the majority of the comments: A) the use of the term Functional Entities; and B) the inclusion of a Registered Entity that represents multiple functional entities. As such, the drafting team revised the definition of Interconnected Element to:

Interconnected Element: A BES Element that electrically joins facilities owned by:
a) separate Registered Entities, or
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

Power System Study

Several commenters disagreed with the definition of "Power System Study" and provided the following input: The term Power System Study (PSS) conflicts with a commonly used phrase for power system stabilizer used in generator excitation controls. The drafting team revised the term was revised to "Protection System Coordination Study". Some additional items were as follows:

1. The study is primarily for transmission facilities and Generator Owners should not be in the Applicability Section. The standard drafting team disagrees and stated in the reply that both entities are responsible and have a role in establishing Protective System coordination.
2. Figures 2 and 5 should be revised to clarify the scope of generator protection to be checked for proper coordination. The standard drafting team revised the language in Figure 2 and 5 to provide clarity.

3. Commenters requested additional clarification to identify the information required to properly demonstrate compliance of a study. The standard drafting team responded by indicating that Requirement R1 Section R1.2 was revised to state that the owner performing the PSCS must provide "a summary of the results of each Protection System Coordination Study performed pursuant to this requirement, (including, at a minimum, the Protection Systems reviewed, any issues identified, and any revisions proposed)." Along with the Protection Systems reviewed, the drafting team believes the minimum information that must be provided in a PSCS summary is the issues that were identified in the PSCS and any proposed revisions that were recommended as a result of the PSCS. Because most owners have their own unique Protection System setting philosophies and methods for performing a PSCS the drafting team believes providing a list of all the information that would comprise a PSCS would not be appropriate to include in Application Guidelines of this standard.

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	No	At our company there is one engineering group doing Protection System Studies for all Functional Entities and for multiple Registered Entities. Reliability is not enhanced by requiring a single engineering group to document and be audited for coordination with itself. An Interconnected Element should be defined as an element that electrically joins facilities that are controlled by separate operating companies and Protection Studies are done by separate engineering groups.
Response: Thank you for your comment. **The drafting team disagrees with your suggested definition of Interconnected Element.** **The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.**		
ACES Standards Collaborators	No	We recommend modifying the definition of Interconnected Element such that is dependent on actual registered entity ownership rather than functional entities. As an example, a generation Element would only be considered an Interconnection Element if the GO and TO were separate corporate entities. If the functions were the same registered entity, coordination would already occur and the generation Elements should not be considered an Interconnected

Organization	Yes or No	Question 2 Comment
		Element. To do otherwise will only cause significant compliance problems that may not support reliability. A utility that owns generation and transmission may not have a clear point of interconnection. This would be especially true for units installed prior to the advent of open access in the mid-1990s. If the point of interconnection is not well defined, how can an Interconnected Element be defined? It would be arbitrary to pick the GSU or an Element in the switchyard. Furthermore, focusing on ownership would actually make the proposed standard consistent with the existing PRC-001-2. That standard does not explicitly require coordination among different function entities within the same registered entity. Interconnection Element definition is proposing an administrative burden of having to coordinate within the same registered function. Documenting coordination efforts made to external functions is reasonable for reliability; however, keeping records of internal coordination is unnecessary. What would an entity be required to show if there was only one protection system engineer in the organization? Would that single person be required to document coordination among him/her self? We feel that this portion of the definition should be struck - it is more appropriate to clarify the coordination of protection system elements should be among external registered entities in the requirements. There should not be any requirement for internal protection system coordination, especially not in a definition.

Response: Thank you for your comment.

The drafting team revised the definition of Interconnected Element; however, we disagree with your example - just because the Transmission Owner and Generator Owner are part of the same Registered Entity does not necessarily mean the same technical groups are involved in the required Protection System Coordination Studies.

The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>American Electric Power</td><td>No</td><td>1. AEP recommends replacing all references to “generator Protection Systems” with “Generator Owner equipment that provides backup system protection”, and suggest adding language to the standard for clarification. The scope of Generator Owner Protection Systems applicable to this standard is not clear from the verbiage within the standard or the definition of Interconnected Element. AEP believes that the SDT did not intend to require the GO to include all generator Protection Systems under this standard (as shown in Figure 2 on page 25 and Figure 5 on page 28 of the clean draft), but instead meant to limit the scope of relaying to be coordinated to only the Generator Owner equipment that provides backup system protection.
2. AEP agrees with the definition of Protection System Study, however, we disagree with using the acronym PSS within the standard as PSS is also the recognized acronym for Power System Stabilizer. Usage of this acronym (for example, in the Process Flow Chart) would cause unnecessary confusion.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.
2. The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS).</td></tr>
<tr><td>PPL Corporation NERC Registered Affiliates</td><td>No</td><td>As per this version, the standard’s protection study requirement seems excessive. The definition of a Protection System Study needs to include identification of the party responsible for performing this work, which should be the TO for the reasons discussed above.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The drafting team believes that although the Transmission Owner may provide the majority of the data and work associated with this standard; however, the drafting team believes the Generator Owner shares the responsibility of ensuring the Protection Systems covered by this standard are properly coordinated.</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
CenterPoint Energy	No	CenterPoint Energy recommends the term “Protection System Study “ be defined as follows: “A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing postulated short circuit Fault events.”
Response: Thank you for your comment. The drafting team believes the definition as noted is sufficient.		
Sacramento Municipal Utility District	No	Clarification is necessary for the definition of “Interconnected Element” which requires the TO and GO function within a company to treat each other as if they were unrelated entities and apply all of this standard’s requirements.
Response: Thank you for your comment. **The drafting team revised the definition of Interconnected Element for clarity. A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).** **The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.**		
FirstEnergy	No	FirstEnergy supports the proposed definition for Protection System Study but believes the Interconnected Element definition requires some modification. As presently written the Interconnected Element definition appears to inadvertently omit coordination of two transmission owners that have tie-lines to each others systems. The two transmission owners are not "separate Functional Entities" but rather two Registered Entities performing the same functional entity (transmission owner) obligations. Additionally, it is understood that the intent is to also require Protection System

Organization	Yes or No	Question 2 Comment
		coordination at interconnection points where the point of interconnection may entail facilities owned by the same NERC Registered Entity having multiple functional entity classifications. FirstEnergy proposes the following definition for Interconnected Element: "Interconnected Element - An Element that electrically joins and interconnects facilities owned by a)separate Registered Entities, or b) the same Registered Entity, but includes those representing multiple functional entity (DP, GO or TO) responsibilities."
Response: Thank you for your comments. **The definition of Interconnected Element has been revised based on your and others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
Hydro One Networks Inc.	No	For Protection System Study: Suggest adding a phrase:"A study between two or more interconnected power system Elements that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults".
Response: Thank you for your comments. **The drafting team believes the existing definition is sufficient and declines to make the suggested change.**		
Liberty Electric Power LLC	No	Functional entity is not defined. System Studies should be defined as "a study performed by a TO that demonstrates.....etc."
Response: Thank you for your comments. **The definition of Interconnected Element has been revised based on your and others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or**		

Organization	Yes or No	Question 2 Comment
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). **The drafting team believes the existing definition of a PSCS is sufficient and that both parties have responsibility to coordinate.**		
Northeast Power Coordinating Council	No	In the proposed definition of Interconnected Element "Functional Entities" is capitalized even though it is not in the NERC Glossary.
Response: Thank you for your comments. **The definition of Interconnected Element has been revised based on your And others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
SCE&G	No	SCE&G disagrees with the definition of "Interconnected Element". More clarity is needed regarding the language "Functional Entities that are part of the same Registered Entity". Entities that are vertically integrated and more specifically those vertically integrated companies that that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves.
Response: Thank you for your comments. **The definition of Interconnected Element has been revised to provide more clarity based on your and others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		

Organization	Yes or No	Question 2 Comment
The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.		
seattle city light	No	Seattle City Light does not agree with the use of Functional Entity in the definition of Interconnected Element. Seattle has several objections. First, although "Functional Entity" is capitalized in the draft Standard, this term is not defined in the NERC Glossary of Terms. A second objection is that "Functional Entity" in this role does not add clarity to the Standard. "Functional Entity" is defined in the NERC Reliability Functional Model as "the term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function." This definition refers to other terms defined only with the Functional Model document ("Task," "Function"). It is not illuminating as to defining the bodies joined by Elements. The third and strongest objection is that use of the term "Functional Entity" in the proposed definition is incorrect and inconsistent with the NERC Functional Model, and as such creates confusion about Standard obligations for entities registered for more than one function. The NERC Functional Mode Version 5 (November 30, 2009) explicitly does not require any particular organization or assignment of functional Tasks or ownership of Elements for any multi-function entity. Functional tasks and Elements exist undifferentiated across an entity as a whole, and the NERC Functional Model document states clearly that no further differentiation is expected, required, or implied. (See, for example, p. 7 "The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term 'functional entity', is a guideline and cannot prescribe responsibility" and p.8 "The Model is independent of any particular organization or market structure.") Seattle City Light, for example, is a vertically integrated municipal utility registered for 11 functions: BA, DP, GO, GOP, LSE, PC, PSE, RP, TO, TOP, and TP.

Organization	Yes or No	Question 2 Comment
		Registration is made without differentiation: no particular sub-organization within Seattle City Light is identified as owning GO Elements, TO Elements, and so on. The Model is simply that Seattle City Light or any other multi-function entity owns a set of Elements s a unit. By contrast the draft definition relies upon differentiation of ownership of Elements within a multi-function entity, so that it can be determined if the proper studies were undertaken or not. Such differentiation is outside the Model and introduces complexities and unintended consequences not envisioned by the Functional Model and the term "Functional Entity." The same confusion about the term Functional Entity occurs in draft Standard COM-003-1. Seattle suggests that NERC immediately clarify the use of this term. Until the definition of the Functional Model is changed and changed significantly, the use of Functional Entity to define obligations within a Standard or definition (other than in the Applicability section) should be eliminated. As is it is simply a misreading, tempting as it may be, to presume that Functional Entity Tasks are assigned with greater granularity than to an organization as a whole. And it is a misreading that does not promote high quality Standards that can be consistently enforced across auditors and across regions. You can do better, and should do better. Seattle apologies that it does not have a suggested fix at this time, because the Functional Entity approach is so fundamentally wrong. Entitly (entirely?) new wording would be required to capture Elements existing within the same registerd Entity.
Response: Thank you for your comment. **The definition of Interconnected Element has been revised based on your and others comments to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
JEA	No	Seems like Interconnect element is too broad and not enough clarity on what a

Organization	Yes or No	Question 2 Comment
		protective system study requires (Ie, is this a setting coordination study? Redundancy studies? Dynamic studies? Duplication of TPL requirements.
Response: Thank you for your comment. **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).** **The drafting team changed the name from Protection System Study to Protection System Coordination Study.** **Note: The Guidelines and Technical Basis section of the Standard provides more information on the scope of a Protection System Coordination Study.**		
Imperial Irrigation District (IID)	No	Suggest replacing Protection System Study with Coordinated Protection System Study.
Response: Thank you for your comment. **The drafting team changed the name from Protection System Study to Protection System Coordination Study.**		
Certain Members of the ISO RTO Council	No	The definition of Interconnected Element is confusing since there are a mix of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest replacing “Functional Entities” with “asset owners” or “facility owners.” If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses The SRC asks if the definition for “Interconnected Facility” needs to be expanded to include situations where a Functional Entity may cross regional boundaries and have facilities that interconnect between the two, which may or may not be the same Registered Entity.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
Independent Electricity System Operator	No	The definition of Interconnected Element is confusion since there is a mixture of Functional Entities and Registered Entities, and some in the industry equate Functional Entities to Registered Entities. To avoid this confusion, we suggest to replace Functional Entities with asset owners or facility owners. If deemed desirable, the asset owners can be qualified by Transmission Owners, Generator Owners and Distribution Providers in parentheses
Response: Thank you for your comment **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
Florida Municipal Power Agency	No	The definition of Interconnected Element limits the scope of the standard too much. The standard only requires coordination between neighboring entities and not of protection of other BES equipment within the same entity, e.g., one TO's transmission line protection with the protection of another transmission line owned by that same TO is not within the definition of Interconnected Element. It would seem that such a requirement would be necessary, e.g., each entity ensures that their protection internal to their system coordinates with itself, and that they coordinate at the boundaries with its neighbors. That would ensure coordination across the BES. Protection System Study definition should have a time element and a consideration for the critical clearing time, e.g., "and demonstrates that the resulting clearing time meets or beats the clearing time

Organization	Yes or No	Question 2 Comment
		used in studies to comply with the TPL standards" or something to that effect
Response: Thank you for your comment. **The drafting team has no evidence that there is widespread miscoordination of Protection Systems associated the BES and therefore the necessity of ensuring that Protection Systems internal to an owner's system should not be included in this standard. However, the drafting team believes that the scope of the standard should require that the individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination at the Interconnected Element.**		
ITC	No	1. The general idea of the Interconnected Element is acceptable. However, when one Registered Entity takes care of coordination between two Functional Entities, or coordinates all protection coordination between the two systems, the documentation will become onerous and not enhance the reliability of the BES. 2. The definition of the Protection System Study still needs further clarification. It is not clear what calculations/documentation must be kept to properly demonstrate compliance with the requirement of a "study." Past practice may have kept calculations and correspondence, which adequately demonstrate "evidence of coordination," but might or might not be adequate to a "protection system study" for future coordination efforts.
Response: Thank you for your comment. 1. **Just because the Transmission Owner and Generator Owner are part of the same Registered Entity does not necessarily mean the same technical groups are involved in the required Protection System Coordination Studies. The drafting team added the following note to the rationale box for Requirement 1: Note: In cases where a single group performs an overall coordination study for a given Interconnected Element; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study would be sufficient for use by both Registered Entities.** 2. **The standard only requires that a summary of the results of each Protection System Coordination Study performed be provided; as such this would be the item to retain.**		

Organization	Yes or No	Question 2 Comment
American Transmssion Company, LLC	No	The Interconnected Element definition should be expanded to clarify that PRC-027 is applicable to only BES Elements as demonstrated in Figure 4 of the Standard's Application Guidelines on pg. 27. o ATC recommends that the SDT please modify the definition of Interconnected Element as follows:"A Bulk Electric System Element that electrically joins separate Functional Entities, including those Functional Entities that are a part of the same Registered Entity" If "Functional Entity" is used and capitalized in the definition above, the term should be defined in the standard or be made part of the "Glossary of Terms Used in NERC Reliability Standards." Furthermore, NERC's "Reliability Functional Model version 5" states: "The following terms are used in the Functional Model and do not appear in the NERC Glossary. Functional Entity. The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function."
Response: Thank you for your comment **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by:** **a) separate Registered Entities, or** **b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).**		
Essential Power, LLC	No	1. The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Functional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear. Is this the transmission line? If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV

Organization	Yes or No	Question 2 Comment
		disconnect switch? Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO? 2.The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO's system.
Response: Thank you for your comment 1. **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).** 2. **The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure the Protection Systems covered by this standard are properly coordinated.**		
Cogentrix Energy Power Management, LLC	No	1.The term Functional Entity needs a definition. It is capitalized in PRC-027 but is not defined in the standard or in the NERC Glossary. It is nonetheless evident that a GO and TO are different Functional Entities, but the nature of the Element that joins them and thereby constitutes the Interconnected Element is unclear. Is this the transmission line? If so, would the TO be responsible for the R1 study if the ownership scope of an independent GO ends at the high-side terminals of the GSU or at an HV disconnect switch? Would the responsibility be shared if, as sometimes happens, the ownership split occurs at the fenceline, leaving a small part of the transmission line the property of the GO while the rest belongs to the TO?

Organization	Yes or No	Question 2 Comment
		2.The definition of a Protection System Study needs to include identification of the party responsible for performing this work. This cannot be the GO if dealing with a deregulated market; since, as explained above, such parties are not allowed access to information about the TO's system.
Response: Thank you for your comments. 1. **The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).** 2. **The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the GO to ensure proper coordination of the protection systems covered by this proposed standard.**		
GP Strategies	No	We do not believe that the drafting team appropriately identified the correct Applicable Functional Entities for this Standard. We also believe existing Standards could be modified to resolve any reliability gap rather than creating a new Standard. As a result, while the Purpose of this standard may seem to be reasonable, we feel that the drafting team should either 1) Change the Purpose to state "To conduct necessary studies to ensure Protection Systems for Interconnected Elements are studied, such that the least number or power system Elements are isolated to clear Faults." 2) And change the Applicable Functional Entities to the Transmission Planner or modify existing Standards, instead, as described below. The short-circuit studies should be conducted by the Transmission Planner. From Appendix 5B of the Registration Criteria the: o Transmission Planner is the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area." o Distribution Provider is the entity that provides and operates the

Organization	Yes or No	Question 2 Comment
		"wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage."TPL-001, TPL-002, and TPL-003 already require the system studies are conducted. These Standards should be modified to include any additional studies that the drafting team feels are a gap. As noted in the drafting teams Rational for Part R2.1 "Short circuit databases are customarily updated annually so the drafting team believes 24 months provides entities flexibility to schedule and perform the new short circuit studies and calculate the percent deviation." That being said, there is no current Requirement for the Distribution Provider to provide the information to the databases so that the Transmission Planner can conduct the studies on the Interconnection Facilities. We recommend that MOD-010 and MOD-012 should be modified to include the Distribution Provider instead. For new facilities, FAC-002-1 already requires the coordination of changes in the Facilities.
Response: Thank you for your comment. 1. **The drafting team revised the Purpose statement to: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.** 2. **The drafting team believes the Applicability as noted is correct. Although is some cases, some of the identified activities may be conducted by the Transmission Planner or other entities, it is the owners that are responsible for ensuring their Protection Systems are coordinated with others.**		
Public Service Enterprise Group	No	What information comprises a Protection System Study (PSS)? In the Application Guidelines, from Figure 1 on p. 24, each owner that receives a PSS is "to review the Protection System setting" associated with the other owner's breaker that would operate to clear a Fault on the transmission line that connects each

Organization	Yes or No	Question 2 Comment
		Interconnected Element. Is this (Protection System settings) the ONLY information that needs to be transmitted in a PSS by each owner? The SDT should itemize ALL of the information it believes needs to be included in a PSS that is to be transmitted between owners of an Interconnected Element and include that information in the examples in the Application Guideline. This information should also be listed into the PSS definition, thereby defining its scope.
Response: Thank you for your comments. **Requirement R1 Part R 1.2 of the standard has been revised to state that after completion of each Protection System Coordination Study (PSCS) the owner performing the PSCS must provide "a summary of the results of each Protection System Coordination Study performed pursuant to this requirement, (including, at a minimum, the Protection Systems reviewed, any issues identified, and any revisions proposed)." Along with the Protection Systems reviewed, the drafting team believes that the minimum information that must be provided in a PSCS summary are the issues that were identified in the PSCS and any proposed revisions that were recommended as a result of the PSCS. Because most owners have their own unique Protection System setting philosophies and methods for performing a PSCS the drafting team believes providing a list of all the information that would comprise a PSCS would not be appropriate to include in Application Guidelines of this standard.**		
Tacoma Power	No	1.Where is the term Functional Entity defined? 2.Consider changing the term Protection System Study to Protection System Coordination Study. There are two reasons for this recommendation. First, the abbreviation for Protection System Study is PSS, which is also the common abbreviation for power system stabilizer. Second, the term Protection System Coordination Study emphasizes the primary purpose of PRC-027-1: to coordinate Protection Systems.
Response: Thank you for your comment. **1. The definition of Interconnected Element has been revised to read: A BES Element that electrically joins facilities owned by: a) separate Registered Entities, or**		

Organization	Yes or No	Question 2 Comment
b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). **2. The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS).**		
Bonneville Power Administration	No	1.With regard to the definition of Interconnected Element, BPA believes the term should be interconnecting element, because the element is not interconnected, rather the systems of the functional entities are interconnected by the element. The point of interconnection between two functional entities is typically where two elements meet, such as between a line and a switch, and it is not a clear which element is the interconnected element. For example, suppose that a line from one entity terminates through a breaker at the bus of another entity's substation. Which is the interconnected element, the line, the breaker, or the bus? In another example, a generator ties to a transmission providers BES through a step-up transformer. Which is the interconnected element, the step-up transformer or the transmission line? Additionally, if a distribution provider taps off of a transmission provider's 230kV line through a disconnect switch, is the disconnect switch the interconnected element? BPA asks that the definition of Interconnecting Element be further clarified to provide the specific criteria that entities are expected to apply to come up with a consistent response in all such instances. The SDT attempted to illustrate the concept of the interconnected element through some examples in the Application Guidelines; however, the selection of the interconnected element in these examples neither follows logically from the standard nor provides the additional clarity necessary to enable industry participants to apply it in a manner that enables all users to come up with the same answers.. BPA believes the standard needs a clearer definition of an interconnected element. 2.With regard to the definition of a protection system study, the definition given

Organization	Yes or No	Question 2 Comment
		is too vague to provide a clear understanding of what is required by the standard.
Response: Thank you for your comments. 1. **The drafting team has provided examples of the applicable Interconnected Elements in the Figures at the end of the standard. This standard applies to the Protection Systems associated with the Interconnected Element installed for the purpose of detecting Faults on BES Elements and that require coordination for isolating those faulted Elements.** 2. **The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS) for clarity.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 2, we have the following general comments: (1) Please clarify why definitions are to remain with standard upon approval and not be moved to the Glossary. Are these definitions applicable only to this particular standard? If this is the case, this could lead to uncertainty if similar terms are going to be used or defined elsewhere. (2) Compliance 1.1 - The word 'Compliance' in the first line should not be capitalized and (CEA) should follow the word 'authority'. Since 'Regional Entity' is a defined term, 'Entity' needs to be capitalized. (3) Compliance 1.2 - The second paragraph should begin with 'Each', not 'The'. We suggest that the reference to an 'Interconnected Facility' in the second paragraph should be changed to 'a Facility associated with an Interconnected Element' to make it consistent with the rest of the standard, including the third paragraph of 1.2.
Response: Thank you for your comments. 1. **Yes, the definitions are intended for use only in this standard.** 2. **The noted corrections have been made.** 3. **The noted corrections have been made.**		

Organization	Yes or No	Question 2 Comment
Texas Reliablity Entity	Yes	The SDT may want to consider additional language for the Protection System Study definition, to clarify that the study demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults as well as clear the Faults within the maximum time frame defined by the Transmission Planner in order to maintain System Stability. Another consideration would be that the study incorporates all of the applicable Fault contingencies (Category B and C) as defined in the NERC Reliability Standards (TPL-002 and TPL-003) or any Regional standards.
Response: Thank you for your comments **The drafting team believes the definition as stated is sufficient.**		
Duke Energy	Yes	The SDT should consider putting the definition of Interconnected Element in the NERC Glossary.
Response: Thank you for your comment; **The drafting team intends for this definition to be used only with this standard.**		
Southwest Power Pool Reliability Standards Development Team	Yes	1. Under figure 2 in the application guidelines the example need to be reviewed and text added to clearly identify the intent of the drafting team. For example is the scope for Generator Owners in figure 2 just the backup system protection for the Transmission Owners system? It's not clear in the examples given. This issue is also present in figure 5. We agree that if the scope is just for the backup system protection it is ok but the wording does not clearly state this. 2. Also using PSS as an acronym for Protection System Study could be confused in the flowchart of this standard with power system stabilizers since there isn't any text to spell out that it is referring to Protection System Study.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. 1. **The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System components need to be coordinated between entities.** 2. **The term Protection System Study (PSS) has been changed to Protection System Coordination Study (PSCS) for clarity.**		
Western Electricity Coordinating Council	Yes	We agree with the definitions, but question the appropriateness of development of terms for a specific standard. Individual Regions are strongly discouraged from defining terms that only apply in a single region. We see the development of a term that is only applicable to a single standard to be a similar situation, leading to a proliferation of terms. If this approach is acceptable to NERC and FERC, we have no concerns.
Response: Thank you for your comment. **This approach is consistent with NERCs standards drafting guidelines.**		
Pepco Holdings Inc & Affiliates	Yes	
Western Small Entity Comment Group	Yes	
Midwest Reliability Organization NERC Standards Review Forum	Yes	
National Grid and Niagara Mohawk (A National Grid Company)	Yes	
Luminant	Yes	
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
SERC Protection and Controls Subcommittee (PCS	Yes	
Tennessee Valley Authority	Yes	
US Bureau of Reclamation	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
pacificorp	Yes	
Southern Company	Yes	
Dynegy	Yes	
Ingleside Cogeneration LP	Yes	
Wisconsin Electric Power Company	Yes	
Ameren	Yes	
Entergy Services, Inc. (Transmission)	Yes	
City of Austin dba Austin Energy	Yes	
Idaho Power Co.	Yes	
Nebraska Public Power District	Yes	
Georgia Transmission Corporation	Yes	

Organization	Yes or No	Question 2 Comment
Xcel Energy	Yes	
City of Tallahassee	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Response: Thank you for your support.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise some of the VSLs.

3. **In Requirement R1, the drafting team modified the time frame to allow entities 48 months to have a documented Protection System Study completed for each Interconnected Element if no Protection System Study exists. Note, the drafting team has allowed inclusion of all previously performed Protection System Studies whose summary of results include, at a minimum, the protective relay settings reviewed, contingencies evaluated, Fault currents used, any issues identified, and any revisions proposed. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Some commenters stated that 48 months in Requirements R1 part 1.1.1 was not enough time for the initial study to be complete. The drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.

A few commenters stated that checking Fault currents and calculating a percent deviation in Requirements R2 part 2.1 ever 24 months was too often. The drafting team revised the timeframe to 60 calendar months, and added the provision that this was not necessary if there was a technical justification why periodic Fault current studies are not necessary for the coordination of Protection Systems associated with Interconnected Elements.

A few commenters requested that the percent deviation trigger in Requirements R1 Part 1.1.2 and Requirement R2 Part 2.2 be changed to 20%. The drafting team left the 10% trigger as an appropriate value.

A few commenters requested that the initial study in Requirements R1 Part 1.1.1 be moved to the implementation plan. The drafting team investigated this as an option but did not make this change. The drafting team stated that it believes the structure of Requirement R1, Part 1.1.1., as currently written, achieves this goal.

A request was made to clarify that an entity was only responsible for performing studies on their Protection System. The drafting team has modified the language of the requirement to read: “Perform a Protection System Coordination Study for each of its Interconnected Elements…”

A request was made to clarify where the 10% threshold in Requirement R1 Part 1.1.2 and calculated in Requirement R2 Part 2.1.2 is applied. The drafting team responded that Requirement R2, Part 2.1.1 refers to maximum available current at the interconnecting bus (total bus fault current). The drafting team has included clarifying language in the Rationale for Requirement R2, Part 2.1 and in the language of Requirement R2, Part 2.1.2 to indicate the need to compare both line-to-ground and three-phase fault current values when performing the calculation to check for a ±10% deviation.

There was a comment asking if a study was performed as a collaborated effort would the acceptance of the results of the study be acceptable. The drafting team stated they recognize that in many cases the owners may do joint studies; but both entities would need to agree with the results of the Protection System Coordination Study for it to be acceptable.

A commenter stated that confirmation from both parties that coordination has been reviewed should be adequate evidence that an entity is in compliance with the standard. The drafting team stated that they believe all Requirements included in this standard support its reliability objective, however Requirement R4 Part 4.2 the standard has been modified to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.

A few commenters stated that Requirement R1 should not apply to Generator Owners. Because Generator Owners are not allowed to have the Transmission Owners information needed for a system study under market rules. The drafting team stated that they do not believe that the Transmission Owner is restricted from providing the Protection System data necessary for the Generator Owner to ensure proper coordination of Protection Systems applicable to this proposed standard.

A few commenters requested clarification as to what comprises a valid PSS. In response, the drafting team has refined the examples given in Requirement R1, Part 1.2 of the minimum information required in a summary of the results of a Protection System Coordination Study (PSCS).

One commenter asked if previous studies were satisfactory to meet the requirements. The drafting team stated that they believe that a previous study can be used as a basis of a summary that includes all the needed information and send it to the other party to review after the effective date of the standard?

Organization	Yes or No	Question 3 Comment
Kansas City Power & Light	No	1. Proposed Requirement R1 allows 48 months to do an initial study with the explanation that there is no evidence of widespread miscoordination. We agree that there is no evidence of widespread miscoordination and therefore 60 months is the proper time frame for an initial study. 2. We have also noticed that there is no question on this comment form for any

Organization	Yes or No	Question 3 Comment
		other comments not addressed by the drafting teams questions. As such we note here that Requirement R1, 1.1.2 lists a 10% change in current as an action point. This implies that a 10% decrease requires action. We do not agree with this since most Protection Studies are done with all generation on. Most of the year all generation is not on with the result that normal operating conditions result in fault currents that are 10% below the maximum used in the Protection System Study. We also disagree with action required for a 10% increase in fault current since our standard relay settings no longer trip for instantaneous ground over current elements and the standard does not allow an entity to state a reason not to run this study or perform the calculations. When we did utilize instantaneous ground over current elements we allowed a 40% margin. We utilize other high speed protection elements not directly affected by changes in fault current. We recommend at least a 20% change in fault current to require action per this standard. 3. Requirement R2 requires that a short circuit study be done every 24 months. As noted above 60 months is proper time for initial study and is also proper for subsequent studies done after the initial study is complete.
Response: Thank you for your comment. 1. **Based on stakeholder comments, the drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.** 2. **The drafting team believes, as noted in the rationale, that the ±10 % change is an appropriate threshold to trigger investigation of the need for a review of Protection Systems. This does not require a new Protection System Coordination Study if an entity provides a technical justification demonstrating why a new study is not necessary.** 3. **The drafting team revised Requirement R2 to require, at least once every 60 calendar months, Transmission Owners perform a short circuit study and calculation of fault current deviation for its Interconnected Elements or provide a technical justification why periodic fault current studies are not necessary for the coordination of Protection Systems associated with Interconnected Elements.**		
ACES Standards Collaborators	No	(1) While we do not disagree with the time frame, we question if it should be

Organization	Yes or No	Question 3 Comment
		part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates, especially when the requirement is asking for documented studies. After the studies are complete, there is not a need for a timeframe. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan is enforceable. (2) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement mirror what is explained in the application guidelines. For instance, we recommend clearly stating in Requirement R1 that the responsible entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Element. The standard is close to capturing this intent with the statement "its System" in Part 1.1. It would be better it if was changed to "Perform a Protection System Study for each of its Protection Systems that are protecting an Interconnected Element." A GO and DP do not really have systems so the current language is not appropriate for these functions. The application guidelines provide this clarity and would be helpful if the intent was clearly stated in the requirements.

Response: Thank you for your comment.

1. **The drafting team agrees your suggestion provides one way of addressing initial requirements to have documented Protections System Coordination Studies for each Interconnected Element. However, the drafting team believes the structure of Requirement R1, Part 1.1.1, as currently written, achieves this goal. Further, NERC performs periodic review of standards and the requirement can be removed at that time, if appropriate.**
2. **Based on your suggestion, the drafting team has modified the language of the requirement to read: "Perform a Protection**

Organization	Yes or No	Question 3 Comment
System Coordination Study for each of its Interconnected Elements…”.		
CenterPoint Energy	No	(a) CenterPoint Energy continues to believe a requirement to have a documented Protection System Study for each existing Interconnected Facility is overly burdensome, unless certain - if not all - existing Interconnected Facilities are exempted; therefore, CenterPoint Energy recommends R1.1.1 be eliminated from PRC-027-1. CenterPoint Energy does not believe a reliability need has been identified to justify that such prescriptive requirements are needed to provide for an adequate level of reliability. The following is stated on page 18 of 28 in PRC-027-1 Draft 2: “records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” The majority of existing Interconnected Facilities have fault-proven, time-proven protection system set points. An existing Interconnected Facility without a documented Protection System Study will eventually be included in a study with system additions and changes, short circuit current increases, and relay panel replacement projects, as well as any analysis of misoperations. (b) While an option has been included in Draft 2 R1.1.3 to allow for a technical justification why a study is not required for certain changes, CenterPoint Energy believes that reasonable thresholds should be established for the changes identified in R3.1. For example, R3.1 requires that “any” change of sequence or mutual coupling impedance must be provided to a Generator Owner. For insignificant changes of sequence or mutual coupling impedance, CenterPoint Energy believes there would be little, if any, reliability benefit of communicating and technically justifying why a study is not required.
Response: Thank you for your comment. **a) The drafting team believes that there is a reliability benefit in ensuring that all existing Protection Systems on Interconnected Elements have been reviewed. The drafting team acknowledges the fact that no immediate reliability concern has been identified and, as such, has allocated an extended time to complete this work.**		

Organization	Yes or No	Question 3 Comment
b) The drafting team believes that information about any change (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnected Element.		
FirstEnergy	No	A) FirstEnergy supports the 48 month timeframe to complete initial Protection System Studies. However, based on the fact that the drafting team may have overlooked system tie points of two transmission systems (see our response to Q2) the completion of Protection Studies may require additional time. B) FE could support a 48 month implementation and encourages the drafting team to consider a staggered plan that requires earlier completion for higher voltage systems. For example, 1) systems operated at 300kV and higher within 24 months, 2) systems operated at 200kV and higher up to 300kV within 36 months and 3) systems operated at 100kV and higher up to 200kV within 48 months. C) As expressed in FirstEnergy's Draft 1 comments, we do not support requirement text that is better placed in an Implementation Plan. A requirement should be written such that it is everlasting. As written, R1 part 1.1.1. has no meaning after the 48 month period expires. D) It is FirstEnergy's experience that the Transmission Owner would likely have the expertise and staff to perform the desired Protection System Study. The team should consider whether or not the DP and GO would typically be performing their own independent study or collaborating with the TO in a supporting role by providing data and reviewing study results. In regard to items B) and C) FirstEnergy proposes the following for Requirement R1. **Start of proposed requirement R1 text **R1. Each Transmission Owner shall perform a Protection System Study for each Interconnected Element on its System associated with a Generator Owner, Distribution Provider or another Transmission Owner. Each study shall include at a minimum: [Violation Risk

Organization	Yes or No	Question 3 Comment
		Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] - the protective relay settings reviewed - power system Elements to be isolated - contingencies evaluated - Fault currents used - any issues identified - any revisions proposed 1.1. Each Transmission Owner shall update its Protection System Study: 1.1.1 Within six calendar months after determining or being notified of a 10% or greater change in Fault current at an interconnecting bus, as described in Requirement R2, or technically justify why such a study is not required. 1.1.2 According to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3, or technically justify why such a study is not required. 1.2. Within 90 calendar days after the completion of each Protection System Study the Transmission Owner shall provide to the owner(s) of the Protection System(s) associated with the Interconnected Element(s) a summary of the results of each Protection System Study performed pursuant to this requirement.**End of proposed requirement R1 text ** E) FirstEnergy recommends that for ease of ordered reading that the numbering of Measures be tied to the Requirement number. For example Requirement R1 has two measures M1 and M2. Consider renumbering to M1.1 and M1.2.

Response: Thank you for your comment.

A) **The drafting team does not agree that it has overlooked the Transmission Owner to Transmission Owner interconnections in the Interconnected Element definition. However, it has been modified as follows: A BES Element that electrically joins facilities owned by:**
   a) separate Registered Entities, or
   b) the same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).

B) **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar**

Organization	Yes or No	Question 3 Comment
months. The drafting team chose not to prescribe how an entity achieves compliance with this requirement; however, an entity may implement its own phased in approach within the confines of a 60 calendar month maximum time frame. C) The drafting team recognizes that your suggestion provides one way of addressing the requirement to have documented Protections System Coordination Studies for each Interconnected Element. However, the drafting team believes the structure of Requirement R1, Part 1.1.1, as currently written, achieves this goal. Further, NERC performs periodic reviews of standards and the requirement can be removed at that time, if appropriate. D) The drafting team recognizes that in many cases the Protection System Coordination Study may be a collaborated effort; but, ultimately it is the owner's responsibility. E) The format used in this standard is consistent with the current NERC standards development process.		
Sacramento Municipal Utility District	No	"The results based objective is that the registered entities communicate and coordinate with each other. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard is met." Performance of a PSS is an intermediate step toward achieving coordination. It does not improve reliability if an entity does not act on it. Only in the final step - when agreed upon changes are made - does system reliability actually improve. The standard should consist of R3.1 (one side makes a change which triggers a review), followed by R4.2 (all parties agree to the changes to be implemented). Documenting the process steps between these two points in time does not improve system reliability.
Response: Thank you for your comment. The drafting team believes all requirements included in this standard support its reliability objective.		
American Electric Power	No	AEP believes that 48 months to complete a Protection System Study is too short of a time frame, especially for Interconnected Elements which do not have an existing study. NERC's rationale for R1 states that "the drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame." If this is the case, then there should be no issue with extending this timeframe. AEP believes

Organization	Yes or No	Question 3 Comment
		that 72 months is a more reasonable timeframe for the following reasons: * The Transmission Owner will need to complete their own studies, as well as provide data to the entities they interconnect with (i.e. TO's, GO's, and DP's). This dependency would effectively shorten the amount of time the functional entity has to complete their studies to less than 48 months. * Before the work of the first bullet point above can be completed, entities must develop an agreed-upon list of Interconnected Elements and associated owners of the Protections System(s) associated with each Element. Once again, the time required to complete this task erodes into the entire time allowed to perform the study. In short, much of this work must be sequentially rather than in parallel, further justifying the need for an increased timeframe. * The resources needed to complete the required studies will also be impacted by a number of other standards currently in draft including: PRC-006-1, PRC-019-1, PRC-024-1, PRC-025-1 and PRC-004-3. The work required to perform both the proposed studies of this standard, as well as the other standards listed above, requires a Subject Matter Expert possessing a specific skillset gained from years of protection experience. Due to the limited number of such SMEs, industry will be very challenged in meeting all the proposed requirements given the limited number of such resources. In addition, the demand for qualified outside resources might be greater than their actual availability due to the time constraints involved.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Salt River Project	No	Agree with timing, but confirmation from both parties that coordination has been reviewed should be adequate evidence.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team stated that they believe all requirements included in this standard support its reliability objective, however Requirement R4 Part 4.2 the standard has been modified to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.		
Florida Municipal Power Agency	No	As worded, R1 seems to require two neighboring entities to perform independent studies. We would hope that the intent of the drafting team is to allow any one entity to do a study and then the neighboring entity accept the results of that study, or to perform a joint study. We suggest the drafting team make conforming changes to allow this.
Response: Thank you for your comment. **The drafting team recognizes that in many cases the owners may do joint studies; but both entities would need to agree with the results of the Protection System Coordination Study. After the initial assessment, the Transmission Owner is the entity required to perform future, periodic fault current studies.** **It is also recognized that, in most cases, it will require a collaborative effort to complete the studies; but ultimately, it is the owners' responsibility to ensure that the requirements of this standard are met.**		
ATCO Electric	No	ATCO Electric (AE) has an existing protection review program that runs on 5 year cycle. Each year, AE review approximately 20% of AE's transmission system to ensure the protection is in place or needs adjustment. Can the drafting team increase 48 month duration to 60 months?
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Bonneville Power Administration	No	BPA believes that the requirement to provide a protection system study for each interconnected element is onerous, and as a result, any amount of time is too

Organization	Yes or No	Question 3 Comment
		short.
Response: Thank you for your comment. **The drafting team believes that there is a reliability benefit in ensuring that all existing Protection Systems on Interconnected Elements have been reviewed. The drafting team acknowledges the fact that no immediate reliability concern has been identified and as such has allocated an extended time to complete this work.**		
Luminant	No	Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: "... Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be within 90 days or in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, or Distribution Provider." This would align with R4.1 that also provides the same time frame. The corresponding measures will also need to be modified if this language is accepted.
Response: Thank you for your comment. **Requirement R1, Part 1.2 requires entities to provide a summary of results of a Protection System Coordination Study (PSCS) to affected entities within 90 days of completion of such a study. Requirement R4, Part 4.1 provides an additional 90 days (or according to an agreed upon schedule) for the recipient of the summary results to review and respond. Considering the 90-day time frame begins after the completion of a PSCS, and only addresses the amount of time allotted to provide a summary of the study to another entity, the drafting team believes there is no need to add the caveat of "an agreed upon schedule" to the 90-day time limit.**		
Western Electricity Coordinating Council	No	Creating a Protection System consists of conducting Protection System studies and incorporating the data into an entity's transmission/generation/distribution system. Protection System studies are not a new concept to entities. In the event that an entity discovers that certain interconnected elements are not included in the Protection System study the entity should not require 48 months

Organization	Yes or No	Question 3 Comment
		to make the needed changes to the study. From a reliability perspective, entities should already have a basic Protection System study in order to have a Protection System. Allowing an additional 48 months creates a potentially large 4 year reliability gap based on entities existing studies and any needed corrections. From a compliance perspective, allowing a 48 month time frame for entities to have a documented Protection System study effectively pushes mandatory compliance for this standard out for an additional four years beyond the effective date. This time frame is excessive and should be reduced to no more than 24 months from the effective date of the standard.
Response: Thank you for your comment. **Based on stakeholder comments, and recognizing there is no evidence of widespread miscoordination of Protection Systems associated with Interconnected Elements, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Northeast Power Coordinating Council	No	Due to the extensive documentation, coupled with the collaboration between entities associated with this requirement, NPCC believes 60 months is a more appropriate time frame to comply. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. An alternative to the "static" time frame discussed above, which would also be acceptable, would be to base the timeframe on a formula that factors in the number of interconnected power system elements that the entity must contend with.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Pepco Holdings Inc & Affiliates	No	Each owner should already possess information demonstrating that their protective devices are set to “coordinate” with adjacent protection systems. However, the documentation that presently exists may not be in the form of a

Organization	Yes or No	Question 3 Comment
		formal "coordination study" in a format suitable for audit purposes. Some guidance should be provided indicating what form of documentation is expected, especially by the TO. For instance, on transmission tie lines between different TO's coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional "coordination study". Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional "coordination study". On the other hand, coordination between GO's and TO's is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a formal review (R1.2) and approval (R4.1) would be required. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The drafting team acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 48 month requirement.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.** **Note: Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS.**		
Southern Company	No	For large entities with hundreds of generators, a longer initial time frame is needed. In addition, consideration should be given to the fact that existing transmission protection and control engineering personnel will be fully engaged

Organization	Yes or No	Question 3 Comment
		in the work associated with FERC order 754 for The next 12+ months.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Georgia Transmission Corporation	No	Guidelines and Technical Basis Req. R1: "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults."......These studies may include graphical coordination....; relay scheme simulation studies....; and sensitivity studies using sequence...., and adequate directional polarizing quantities. This activity will be onerous without a full system model and software to perform studies that would check coordination of stacked curves and stepped distance relays. Of particular note is the question of adequate directional polarizing quantities. There should be an expected minimum requirement such as time overcurrent plots and zone distance plots of the existing relay settings for the terminal with the fault points used as the basis. This data would then be used to indicate if the 10% point has been reached that would require a new coordination follow up at the end of the next 24 month fault study.
Response: Thank you for your comment. **Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS. The ±10% threshold relates to the fault current at the interconnected bus; not individual relay tolerances.**		
National Grid and Niagara Mohawk (A National Grid Company)	No	How would "fault currents used" be presented for coordination of distance relays ? Also if the above items must be included, at a minimum, they need to be enumerated in requirement R1.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
Each company must determine proper use of fault currents for their particular Protection System components. The language of the Requirement R1, Part 1.2 has been modified to indicate "(including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions proposed)".		
Hydro One Networks Inc.	No	Hydro One believes 60 months is a more appropriate time frame to conduct, document and obtain consensus for a protection system study. This timeframe is also more in line with the timeframe proposed in the draft PRC-019-1 in Project 2007-09. Large entities and small entities have the same time frame to complete this work which seems unreasonable. Alternatively, an extended period should be provided based on a formula that factors the quantity of interconnected power system elements.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration, like many other Generator Owners, does not typically perform fault studies unless we have made material changes to our transmission system interconnection. Even then, we provide modeling data to the appropriate Transmission Owners and Transmission Planners, who execute the assessments on a Regionally-standardized platform. We are not convinced that we can add value to this process - other than to demonstrate that the information required by the TO and TP was provided, and the study took place. In our view, the requirement should clearly accommodate this working arrangement. As it reads now, it seems like both the GO and the TO must perform separate assessments. The extra costs that we will incur to commission external consultants is difficult to justify when there are so many other pressing priorities (e.g.; cold weather preparedness).
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
The drafting team recognizes that in many cases the owners may do joint studies; but both entities would need to agree with the results of the Protection System Coordination Study. After the initial assessment, the Transmission Owner is the entity required to perform future, periodic Fault current studies. **It is also recognized that, in most cases, it will require a collaborative effort to complete the studies; but ultimately, it is the owners' responsibility to ensure that the requirements of this standard are met.**		
Dynegy	No	Perhaps R1 could be reworded to answer the following question: "If an entity registered only as a GO owns relays that trip the generator alone (and not relays detecting a fault on any transmission lines), does this Standard apply?"
Response: Thank you for your comment. **Per the Applicability section of the standard, if the Generator Owner owns no Protection Systems that require coordination with other owners, then the standard would not apply to those Protection Systems.**		
Portland General Electric Co	No	Portland General Electric Company appreciates the drafting team's consideration of comments. Since there wasn't a general comment section at the end of this form, the discussion of timeframes seems appropriate here. The effective date (the first quarter six months after approval) does not allow sufficient time for compliance. This standard will require that entities include in all interconnection agreements a detailed protection coordination schedule or be subject to the long timelines detailed in the standard. None of the agreements (if they even exist) for projects six months out include a protection coordination schedule, nor do their project schedules accommodate the long durations detailed in the standard. Agreements will also need to be drawn up for smaller projects in order to document a protection coordination schedule, lest the interconnecting utility prevents us from energizing by taking the full 90 days to review the relay settings. In addition, entities may need at least one additional resource to conduct the bi-annual coordination studies and manage the interconnection due dates. PGE suggests an implementation period of 24

Organization	Yes or No	Question 3 Comment
		months since planning is done more than a year in advance.
Response: Thank you for your comment. **The drafting team believes the elements of Requirement R3 provide sufficient flexibility for project scheduling with regard to achieving proper Protection System Coordination prior to energization.** **Based on stakeholder comments, the drafting team has extended the timeframe for Requirement R1, Part 1.1.1 and the periodic Fault current study to 60 calendar months.**		
Liberty Electric Power LLC	No	R1 should not apply to GOs. GOs are not allowed to have the TO information needed for a system study under market rules.
Response: Thank you for your comment. **The drafting team does not believe that the Transmission Owner is restricted from providing the Protection System data necessary for the Generator Owner to ensure proper coordination of Protection Systems applicable to this proposed standard.**		
ReliabilityFirst	No	ReliabilityFirst abstains and offers the following comments for consideration: 1. Requirement R1, Part 1.1.1a. ReliabilityFirst questions the rationale for the 48 calendar month window to perform a Protection System Study if NO study exists. ReliabilityFirst believes that a Protection System Study is one of the fundamental reasons for the standard and believes if NO study had ever been performed, one should be performed as soon as possible (12 months). Within the rationale section, the drafting team states: “The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame.” With no widespread mis-coordination of protection systems, ReliabilityFirst questions the actual need for the standard itself. 2. It is not clear where the 10% threshold in Part 1.1.2 and calculated in Part 2.1.2 is applied. Does the 10% threshold apply to the total bus Fault current at the interconnecting bus or the contributing Elements? If it is the total, then

Organization	Yes or No	Question 3 Comment
		there are situations where some of the sources into the bus may change their contribution quite a bit more than the 10% threshold but yet the total change could be less than 10%. Protective relaying is set in reference to the Element it is protecting or, to be more precise, the instrument transformers associated with an Element. The 10% threshold should be applied to the Interconnecting Element as its contributing quantities could change significantly even if the total Fault current stayed nearly the same. It is the Fault quantities on the Element that the interconnection protection sees - not the total bus Fault current (unless the Interconnecting Element is a bus). It is also not clear which phase or sequence currents are being used in the %Deviation calculation. Is it 3I0 (3 times zero sequence) current for single line to ground Faults and I1 (positive sequence) current for 3-phase Faults? It should be noted that if variations in Fault current of 10% are acceptable, then entities may need to adjust their criteria to use margins of 15% or more to consider other sources of error such as relay and instrument transformer accuracy.
Response: Thank you for your comment. 1. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months. Additionally, the drafting team believes there is a reliability benefit to require that all interconnected Elements have a valid Protection System Coordination Study in order to ensure coordination between owners of interconnected Elements.** 2. **Requirement R2, Part 2.1.1 refers to maximum available current at the interconnecting bus (total bus fault current). The drafting team has included clarifying language in the Rationale for Requirement R2, Part 2.1 and in the language of Requirement R2, Part 2.1.2 to indicate the need to compare both line-to-ground and three-phase fault current values when performing the calculation to check for a ±10% deviation.**		
Entergy Services, Inc. (Transmission)	No	Request consideration in replacing the time increment of 48 months with 4 years for the time frame.
Response: Thank you for your comment. **The drafting team has retained the use of months; however, the drafting team has modified the timeframe for Requirement R1,**		

Organization	Yes or No	Question 3 Comment
Part 1.1.1 to 60 calendar months.		
PPL Corporation NERC Registered Affiliates	No	Sixty months would be more appropriate to study all the interconnections. There has not been a major problem with mis-coordination of Protection Systems associated with Interconnected Elements. Also, the standard does not fully address what all should be included in a Protection System Study.R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
ITC	No	The amount of work required to comply with this requirement may be significant and may impact ongoing efforts to upgrade and improve the system. The above items that need to be documented can often be discussed and agreed to verbally between parties and are were often not part of a permanent record. The additional record keeping required may be significant and not add to the reliability of the BES.
Response: Thank you for your comment. **The drafting team does not believe a verbal agreement is measurable or auditable.**		
Western Small Entity Comment Group	No	The comment group agrees that Protection Systems associated with Interconnected Elements must be coordinated. However, the reliability goal should be strictly focused on documenting the associated owners (parties) are cooperating, and in agreement with protection settings to achieve proper coordination. A requirement to have a documented Protection System Study completed will not improve on a simple statement from the parties that proper coordination has been agreed upon. Provision of a Protection System Study as

Organization	Yes or No	Question 3 Comment
		compliance evidence (in whole or a summary) implies recourse to check its completeness or accuracy. For complex systems, this is very subjective. However, the Standard as written intends to make no effort to verify the completeness or accuracy of a Protection System Study; the intent is to simply verify that it exists. Since the Protection System Study is not subject to review, its production as compliance evidence is nothing more than added bulk.
Response: Thank you for your comment. **Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS. Minimum elements required in the summary results are provided in Requirement R1, Part 1.2. It is the responsibility of the respective owners to ensure the accuracy and completeness of the study results.**		
Public Service Enterprise Group	No	The issue is consistency in what comprises a valid PSS. For example, for "contingencies evaluated," it seems that each owner should evaluate a core set of the same contingencies as opposed to this being an owner-by-owner decision. The lack of specificity as to what is required for a PSS is the issue.
Response: Thank you for your comment. **A Protection System Coordination Study (PSCS), by definition within PRC-027, must demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Most entities have internal procedures regarding the performance of coordination studies that produce the results required, but may not involve the exact same process or procedures that another entity follows to achieve Protection System coordination. The drafting team chose not to specifically dictate the elements of this process, but rather to continue to allow entities to "demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults" according to their own internal procedures.** **The examples of information required in a "summary" of the results of a PSCS represent a minimum set of data that must be provided so the receiving entity can effectively assess coordination of the system. The drafting team has revised the examples to add clarity and the particular example provided in your comment has been removed.**		
Midwest Reliability Organization	No	The NSRF recommends that this Standard be filtered through the paragraph 81

Organization	Yes or No	Question 3 Comment
NERC Standards Review Forum		criteria. If not, the NSRF recommends the following items. 1. Although supportive of the extended timeframe in R1, the NSRF is concerned that the proposed Part 1.2 is overly prescriptive. Considering the sheer quantity of microprocessor relay settings that could potentially be reviewed as part of a Protection System Study, having to provide associated owner(s) the results of every protective relay setting reviewed would be unnecessarily burdensome with little benefit to reliability. Recommend the drafting team revise Part 1.2 to require entities to only provide information related to settings being proposed for change and have all other settings be made available upon request. 2. Please clarify the application of R1, Part 1.2 in the event that both ends of the Interconnected Element are owned by the same entity. In consideration that final settings and internal documentation would provide proof that everything was looked at accordingly, would the entity still need to develop and distribute a summary internally as well? Recommend revising Part 1.2 to only require functionally separate entities to provide documentation of the results of the Protection System Study. 3. Rather than specify the details to be shared as a result of a Protection System Study, recommend Part 1.2 be modified to remove “power system Elements to be isolated, contingencies evaluated” as a minimum requirement. Having entities share their evaluation methods with other Entities appears to be unnecessary administrative work. Considering that it is the responsibility of the individual entity to perform their studies correctly, another entity should not have to worry about, nor does it have the responsibility for keeping tabs on, whether an external study was done to a single or double contingency level, what external Facilities become isolated, etc. Additionally, the NSRF is concerned with the phrase “Fault current used” as it applies to R1, Part 1.2. In consideration that Fault current values do not necessarily mean that two entities are using

Organization	Yes or No	Question 3 Comment
		like models, recommend a comparison of boundary equivalents be used instead to ensure that the models are comparable between entities. If not, entities would potentially be sharing every value for every iteration to ensure like models. Suggested revisions to R1, Part 1.2 in support of the above comments are as follows: 1.2. Within 90 calendar days after the completion of each Protection System Study provide to the owner(s) of the Protection System(s) associated with Interconnected Element(s) that include two or more Registered Entities, a summary of the results of each Protection System Study performed pursuant to this requirement, (including, at a minimum, proposed revisions to the protective relay settings reviewed, power system Elements to be isolated, contingencies evaluated, boundary equivalents at necessary buses Fault currents used, any issues identified, and any additional revisions proposed). If existing documentation does not include enough detail to meet the requirement for an acceptable Protection System Study, utilities will be forced to add to the existing documentation for compliance purposes even though the existing settings coordination is adequate. This will place additional compliance burden on utilities while not necessarily improving reliability. Since there is no evidence of widespread mis-coordination of Protection Systems associated with Interconnection Elements, it would seem reasonable to have this standard apply to any changes made to an existing Protection System or all new Protection Systems.

Response: Thank you for your comment.

1. **In response to stakeholder comments, the drafting team has refined the examples given in Requirement R1, Part 1.2 of the minimum information required in a summary of the results of a Protection System Coordination Study (PSCS).**
2. **The drafting team believes, even for functional entities under the umbrella of a single company, there is a reliability benefit associated with the provision for the information required in a summary of results of a PSCS from Transmission Owner to**

Organization	Yes or No	Question 3 Comment
Generator Owner. The drafting team does acknowledge that in the cases where a single person is doing the overall coordination for a given interconnection; a single document that provides the requirements for a summary of the results of the Protection System Coordination Study should be sufficient for use by both owners. **3. In response to stakeholder comments, the drafting team has refined the examples given in Requirement R1, Part 1.2 of the minimum information required in a summary of the results of a Protection System Coordination Study. The particular items you mentioned were removed from the requirement.**		
American Transmssion Company, LLC	No	The drafting team states that there is no evidence of wide spread misoperation due to lack of coordination. However, R1 requires a utility to establish an evidence package of legacy coordination that predates PRC-001's effective date. While 48 months is an improvement to PRC-027, that timeframe still imposes a significant burden on utilities, especially those that are not vertically integrated. ATC recommends that the drafting team consider changing the implementation period for R1 from 48 months to 72 months.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Essential Power, LLC	No	The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.
Response: Thank you for your comment. **The drafting team believes that the Generator Owner is an appropriate Applicable Entity for this Standard since they often apply Protection Systems that require coordination with other owners' Protection Systems.**		
Cogentrix Energy Power Management, LLC	No	The time frame is not the issue. R1 should apply only to TOs, as explained above. The only responsibilities of GOs should be those already stated in PRC-001 regarding changes to equipment.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. **The drafting team believes that the Generator Owner is an appropriate Applicable Entity for this Standard since they often apply Protection Systems that require coordination with other owners' Protection Systems.**		
Nebraska Public Power District	No	To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6 years based on two audit periods (time depends on the number of applicable system ties as well).
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Southwest Power Pool Reliability Standards Development Team	No	We are concerned that 48 months could still not be sufficient for these studies. We would ask that the team consider 72 months. There is a concern that with all the companies having new standards to comply with, the Transmission Owners/Generation Owners are being overloaded and have the same resources.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.**		
Tennessee Valley Authority	No	We do not feel like 48 months is a reasonable timeframe to meet the minimum requirements for Protection System Studies (PSS). In the current form of the standard, for an existing PSS to be valid, several minimum requirements are given in R1.2. While this is a good requirement for new PSS, it eliminates almost all of our existing PSS as being valid. We have the stance that many of our

Organization	Yes or No	Question 3 Comment
		existing PSS are of a high quality and should be considered valid, but do not meet the minimum requirements from R1.2. We recommend allowing existing PSS to be submitted in their current form between all protection system owners of an Interconnected Element within a reasonable time frame of the standard effective date and allowing the owners to approve the existing PSS as valid if they desire. Then, that existing PSS could be used as the baseline PSS until the 10% change in fault occurs from the existing dated PSS. At that time, a new PSS should be performed to meet the minimum requirements as outlined in R1.2.
Response: Thank you for your comment. **The drafting team recognizes that entities approach the process of protection system coordination according to individual entity policy and procedure, yet still achieve the same high quality results in the end. Based on your and others' comments, the drafting team has modified the timeframe associated with Requirement R1, Part 1.1.1 to 60 calendar months and revised the minimum information required in a summary of the results of a Protection System Coordination Study. The drafting team believes that a previous study can be used as a basis of a summary that includes all the needed information and send it to the other party to review after the effective date of the standard.**		
Wisconsin Electric Power Company	No	1.We strongly believe that 60 months would be a more achievable time frame to study the many interconnections that an entity may have. This will also allow Generator Owners the time needed to gain the resources required to perform these studies, since they may not be presently so equipped. As stated by the drafting team in the rationale for R1 there is no evidence of wide spread mis-coordination of Protection Systems associated with Interconnected Elements. 2.It would also be helpful to provide a better description of what is required to be included in a Protection System Study. For example, is the study required to include pilot scheme timing and element coordination, breaker failure coordination, coordination under minimum and maximum fault current cases, etc?
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
1. **Based on stakeholder comments, the drafting team has modified the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months.** 2. **A Protection System Coordination Study (PSCS), by definition within PRC-027, must demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults. Most entities have internal procedures regarding the performance of coordination studies that produce the results required, but may not involve the exact same process or procedures that another entity follows to achieve Protection System coordination. The drafting team chose not to specifically dictate the elements of this process, but rather to continue to allow entities to "demonstrate that existing or proposed Protection Systems operate in the desired sequence for clearing Faults" according to their own internal procedures.** **The examples of information required in a "summary" of the results of a PSCS represent a minimum set of data that must be provided so the receiving entity can effectively assess coordination of the system. The drafting team has revised the examples to add clarity and the particular example provided in your comment has been removed.**		
Ameren	Yes	Note- No. 1 objection is above in Question 1 (2) Requirement R2 requires short circuit study every 24 months even though the drafting team's own rationale is that other requirements will trigger Protection System Studies first. Thus we believe that R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. (3) VSL escalation in 10 days is not representative of the severity of the violation. The drafting team correctly points out in R1 rationale that it "has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements." We have about 500 Interconnected Elements per our present understanding of Draft 2 definitions and guidance. We recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity's Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to

Organization	Yes or No	Question 3 Comment
		5% so that even a single Interconnected Element would be a violation.
Response: Thank you for your comment. 1. **The drafting team revised Requirement R2 to require, at least once every 60 calendar months, Transmission Owners perform a short circuit study and calculation of Fault current deviation for its Interconnected Elements or provide a technical justification why periodic fault current studies are not necessary for the coordination of Protection Systems associated with Interconnected Elements.** 2. **Some of the VSL increments have been increased but the drafting team believes the 10-day increments are appropriate in some cases. The use of percentages in the VSLs for this standard is not permitted because the requirements in the standard are specific to each Interconnected Element.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 3, we have the following general comments: (1) R2, 2.1.1 - Reference to the Protection System Study should be the most recent Protection System Study to be consistent with the rest of the requirement and the use of the word 'available' is a little problematic. What if no study exists? As we read it, the requirement to do a study is within 48 months of the effective date of the standard, while the requirement to do a short circuit study is at least every 24 months. If the Protection System Study is not available, is there no requirement to do the short circuit study? (2) R2, 2.2 - For clarity, we suggest rewording the first sentence to read 'Within 30 calendar days after identification, through the calculation performed pursuant to Requirement R2, Part 2.1.2, of a deviation in...' (3) R3, 3.1 - No time frame is given and it is unclear as to whether these details are to be only for proposed or future changes or additions, or whether it can be 'notice after the fact' (when read with the remaining requirements, it would be assumed it is 'prior notice', but that's not clear on the face of this part 3.1). In addition, should 'facilities' be capitalized in 3.1? Also, there needs to be consistent references to 'changes and additions' or just 'changes' within this R3

Organization	Yes or No	Question 3 Comment
		as currently there are references to both made. (4) R3, 3.2 - We suggest moving the time frame to the start of the Part for consistency with the drafting of other Parts and for ease of reading. (5) R3, 3.3 - We believe that the timeline is incomplete. Assuming that the timeline is meant to be 'within 30 calendar days of the (proposed?) changes or additions being made'. (6) VSLs/VRF table: R1, R3 - For consistency, the references should read 'less than or equal to 10 calendar days' instead of '10 calendar days or less'. (7) VSLs/VRF table: R4 - All of the references to 4.1 appear to be incorrect because 4.1, as currently drafted, does not require confirmation of acceptance of the summary results.
Response: Thank you for your comment. 1. **If you do not have a Protection System Coordination Study, you cannot perform a Fault current comparison.** 2. **The drafting team considered this alternate language; however, we believe the existing language is sufficient.** 3. **The drafting team believes that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated. The drafting team capitalized "Facilities" but believes the other language is appropriate as written.** 4. **The drafting team believes the overall language of the requirement is appropriate as written.** 5. **The changes noted in Requirement R3, Part 3.3 are not proposed changes, they are indentified as 'changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components'.** 6. **The drafting team made the suggested changes for consistency in the VSL language.** 7. **The VSLs have been modified for consistency with the Requirement 4, Part 4.1 language.**		
Operational Compliance	Yes	It would be great if NERC provided a common format for all of us to use when providing this information
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
Acceptable evidence (per Measure M1) is a Protection System Coordination Study (PSCS) or a summary of the results of the PSCS. **The examples of information required in a “summary” of the results of a PSCS represent a minimum set of data that must be provided so the receiving entity can effectively assess coordination of the system. The drafting team has revised the examples to add clarity.**		
JEA	Yes	There is no place to put in a comment for R2 so this is for R2. We believe that the requirement to perform an analysis should be changed from once every 24 months to once every 36 months. Whenever changes are done to the system an analysis is done so this for areas that have not changed and we believe that once every 3 years should be sufficient.
Response: Thank you for your comment. **Based on stakeholder comments, the drafting team extended the 24 month review of Fault currents to 60 calendar months.**		
Imperial Irrigation District (IID)	Yes	
GP Strategies	Yes	
Dominion	Yes	
SERC Protection and Controls Subcommittee (PCS	Yes	
seattle city light	Yes	
Certain Members of the ISO RTO Council	Yes	
Duke Energy	Yes	
US Bureau of Reclamation	Yes	

Organization	Yes or No	Question 3 Comment
pacificorp	Yes	
Texas Reliablity Entity	Yes	
Tacoma Power	Yes	
City of Austin dba Austin Energy	Yes	
Independent Electricity System Operator	Yes	
Idaho Power Co.	Yes	
Exelon Corporation and its affiliates	Yes	
Xcel Energy	Yes	
City of Tallahassee	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Thank you for your support.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and

Organization	Yes or No	Question 3 Comment
communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise some of the VSLs.		

4. **In Requirement R4, the drafting team replaced the need to ‘reach agreement’ with ‘confirming acceptance.’ Do you agree with this change? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

The majority of the commenters agreed with the change from ‘reach agreement’ to ‘confirming acceptance’.

Several commenters felt the change made the requirement more ambiguous and were unclear what ‘confirming acceptance’ means. The confirming acceptance indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agree with the other entities philosophy. The drafting team modified Requirement 4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.

A few commenters felt Requirement R4, Part 4.2 was unnecessary and should be eliminated. The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.

A few commenters felt the standard should include a conflict resolution process for situations when ‘acceptance’ cannot be reached. The drafting team believes that any conflict resolution should be handled through normal business practices.

Organization	Yes or No	Question 4 Comment
Manitoba Hydro	No	(1) R4, 4.2 - The concept of ‘accept’ the changes are problematic. We are unclear as to what exactly this means? Is it something more than acknowledging that the changes are occurring? Does it go so far as ‘agreement’ with the changes? What happens if the owner does not ‘accept’ the changes? (2) R4, 4.1 - For consistency with wording the in R3, ‘planned change’ should be ‘proposed change’ or ‘addition’.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. 1. **Based on stakeholder comments, the drafting team modified Requirement 4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.** 2. **The suggested change has been made.**		
Georgia Transmission Corporation	No	1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the "art and science" of protective relaying. Therefore, interpretation of 'confirming acceptance' means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included using industry protection practices. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.
Response: Thank you for your comment. 1. **The drafting team acknowledges that entities may have differing protection philosophies. The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the**		

Organization	Yes or No	Question 4 Comment
affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues. 2. The drafting team believes that any conflict resolution should be handled through normal business practices.		
Bonneville Power Administration	No	According to this standard, something as simple as changing a CT ratio must now be communicated to all interconnected functional entities and documented. The interconnected functional entities must then “confirm acceptance” of the CT ratio change before the change can be made. The acceptance must then also be documented. This level of bureaucracy is unnecessary and counterproductive. The change from “reach agreement” to “confirming acceptance” is irrelevant.
Response: Thank you for your comment. **Yes, current transformer ratios are listed as one of the changes listed in Requirement R3, Part 3.1 that must be communicated. The drafting team does not understand any circumstance where a current transformer ratio in a Protection System would be changed that would not result in a change to the Protection System settings.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
FirstEnergy	No	FirstEnergy proposes that R4 Part 4.2 be deleted. The requirement is overly burdensome and R4 part 4.1 should provide sufficient evidence of whether or not the entity receiving study results believed any further action was required. Absent any such notification, the party would by default be accepting of the information. In regard to need for "acceptance" prior to planned changes FirstEnergy does not believe this is necessary. The drafting team in its rationale provided for Requirement R1 indicated "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements" therefore we do not believe R4 part 4.2 is a necessary reliability requirement. Furthermore, other changes (R3 part 3.3) potentially

Organization	Yes or No	Question 4 Comment
		trigger upgraded Protection System Studies being communicated without “acceptance” prior to their implementation.
Response: Thank you for your comment. **The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Nebraska Public Power District	No	Getting acceptance within the required time frame is not in the control of the requestor. The concern is the numerous timelines in this standard that require timely responses will create an overly complex standard that will be difficult implement and to audit. The starting points for the timelines will be difficult to audit as well since much of this must be determined between two or more entities. How will enforcement view a requesting utility that sends a timely request but the response is a late confirmation of acceptance? The numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking dated communications between entities. This draft standard includes time lines ranging from “prior to in service date, 30 days, 90 days, 6 months, 2 years and 4 years”. There should be fewer and simpler time lines with the focus on if the sharing of information took place and not on when did it take place. The SDT statement below should be generalized to the standard as a whole:”The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in

Organization	Yes or No	Question 4 Comment
		a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date,"At a minimum remove the calendar day references and make them all 6 months for simplicity so the option is to use and agreed upon time or 6 months. Possible Suggestions: A simpler method would be after the initial 4 years to perform a study then every 24 months perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the interconnecting bus per Requirement R1 and demonstrate that the fault model was provided to the interconnecting entities within this time period along with the settings so the receiving entity can review against their design. Auditing would verify this data was sent on a two year schedule. For new protection interfaces verify protection studies or relay settings or summaries of studies were exchanged for review prior to the equipment going in service.
Response: Thank you for your comment. **The drafting team believes the timeframes in the standard, as revised, are necessary and appropriate.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration still holds to the position that a dispute resolution process needs to be defined should we reach an impasse with the TO. R4 still requires that both parties "accept" the proposed change - which means that one or the other could unreasonably demand an Protection System-related expenditure without any need to demonstrate that a corresponding reliability benefit will be realized. It is not apparent to us that this situation is already addressed in NERC's Rules of Procedure, which ultimately is the governing document for continent-wide Reliability Standards.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal business practices.**		

Organization	Yes or No	Question 4 Comment
National Grid and Niagara Mohawk (A National Grid Company)	No	It is not clear where the old text "reach agreement" and the new text "confirming acceptance" were/are used. Also, "confirming acceptance" is vague in meaning.
Response: Thank you for your comment. **The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Midwest Reliability Organization NERC Standards Review Forum	No	R4, Part 4.2: In consideration that R4, Part 4.1 already requires entities to review the results of a Protection System Study and provide any related feedback, recommend Part 4.2 be removed from the standard. Without additional guidance within the standard specifying the timeframe in which an entity must provide its confirmation, the entity implementing the planned change could potentially be left waiting indefinitely for confirmation despite the study already being reviewed and accepted as part of Part 4.1. If part 4.2 is not removed, recommend that additional guidance be provided concerning time frames (90 days?).
Response: Thank you for your comment. **The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Xcel Energy	No	Requirement 4.2 requires entities to receive evidence confirming acceptance of changes prior to implementing these changes. This coordination already occurs,

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>and we believe this should be a standard practice for all applicable entities. However, we do not agree that this documentation-only requirement is necessary or beneficial to reliability. Instead, we believe this would deter valuable resources to unnecessary compliance evidence activities. Therefore, we recommend that this requirement be eliminated.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.

Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.</td></tr>
<tr><td>Wisconsin Electric Power Company</td><td>No</td><td>The current draft standard lacks any clear responsibility for performing the complete Protection System Study, especially if the interconnected parties cannot accept or reach an agreement. The recommended change is to make the Transmission Owner accountable for the overall Protection System Study, at least at the Generator-Transmission interconnections. The other entities such as Generator Owners should be responsible to provide the necessary data required for the overall study. This makes the most sense based on limited resources and capabilities, as well as access to all data. This is especially true for independent Generator Owners that operate in the deregulated market. It is not feasible to make all entities somehow responsible for the study.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The drafting team believes that the Generator Owner is an appropriate Applicable Entity for this standard since they often apply Protection Systems that require coordination with other owners' Protection Systems.</td></tr>
<tr><td>Southern Company</td><td>No</td><td>The parties at the opposite ends of an interconnecting facility may not have the same protection philosophies, and acceptance may not be achievable. It is</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		unclear what it means to confirm acceptance. Does this mean that the two must come to an agreement for each other's protection system settings, or is it acceptable to agree that we disagree?
Response: Thank you for your comment. **The drafting team acknowledges that entities may have differing protection philosophies.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
City of Tallahassee	No	These phrases do not appear to be contained within draft two.
Response: Thank you for your comment. **The drafting team intent was to indicate the thought behind the fact that language was changed in R4.2 to indicate 'confirm the owner(s) of each Facility associated with the affected Interconnected Element accept...'** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Northeast Power Coordinating Council	No	This change is more ambiguous than reach agreement. How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to confirm acceptance?
Response: Thank you for your comment. **The confirming acceptance indicated that the entity had not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agreed with the other entities philosophy.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications**		

Organization	Yes or No	Question 4 Comment
associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.		
Hydro One Networks Inc.	No	This change seems more ambigious than “reach agreement”. How can changes to Protection Systems occur unless agreement is reached via a signed off Protection System Study? What does it mean to “confirm acceptance”?
Response: Thank you for your comment. **The confirming acceptance indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agree with the other entities philosophy.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Texas Reliablity Entity	No	TRE agrees with the need to notify the Facility Owner of the proposed changes. However, if the receiving entity does not agree with the proposed changes, there needs to be a venue to reach consensus. The receiving entity should be able to suggest changes based on technical rationale to resolve the disparities. A provision for dispute resolution needs to be provided. TRE suggests re-wording R4.2 to - “Prior to implementing any planned change(s) associated with Requirement R3, Part 3.1, notify the Facility owner(s) associated with the affected Interconnected Element. If consensus cannot be reached on the proposed Protection System(s) changes, each entity shall document the technical rationale for its position on each disputed issue prior to implementation.”
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
The drafting team believes that any conflict resolution should be handled through normal business practices. **Note: Prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
Pepco Holdings Inc & Affiliates	No	We find that changing the wording from "confirming acceptance" to "reaching agreement" does little to address the root problem associated with mandating mutual agreement. We suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined below: Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What I f agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is

Organization	Yes or No	Question 4 Comment
		reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. It is unreasonable and unfair to hold one party non-compliant due to the failure of another party to reach agreement. Furthermore, in the example provided above, it is a detriment to reliability to delay implementation of the setting change on breaker D just because mutual agreement could not be reached.It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the "Protection System Study" and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing a clear division of responsibilities and assignment of who will be held non-compliant if agreement cannot be reached is unfair to either party.

Response: Thank you for your comment.

The drafting team believes that any conflict resolution should be handled through normal business practices.

The drafting team believes that Requirement R4, Part 4.2 is integral to the intent of this standard.

Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications

Organization	Yes or No	Question 4 Comment
associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.		
ACES Standards Collaborators	Yes	(1) We had no issues with the use of agreement in the previous version. Coordination of protection systems is important enough to obtain agreement. Furthermore, we believe confirming acceptance and reaching agreement are synonymous. If two entities need to “resolve differences and confirm acceptance that their Protection Systems are coordinated,” that is the same as stating that the entities need to reach an agreement.
Response: Thank you for your comment and support. **The changes were made based on previous comments from those that believed agreement was too strong. They indicated that confirming acceptance indicates that the entity has not identified any potential coordination issues with the proposed Protection System change, not necessarily that they agreed with the other entity’s philosophy.** **Note: The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**		
SERC Protection and Controls Subcommittee (PCS	Yes	1) The protection criteria and philosophies between entities can differ. For example, one entity may use the practice of coordinating for normal and single worst case contingency conditions, which is included in information/documentation provided to the neighboring entity in such Protection System Studies. The neighboring entity may have a slightly different protection criteria or philosophy, so exceptions may be required on a case by case basis using the “art and science” of protective relaying. Therefore, interpretation of ‘confirming acceptance’ means there may be differences in protection elements used by each entity but that there were no major disagreements and that generally the methods were acceptable and included

Organization	Yes or No	Question 4 Comment
		using industry protection practices. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance.
Response: Thank you for your comment and support. 1. **The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.** 2. **The drafting team believes that any conflict resolution should be handled through normal business practices.**		
Dominion	Yes	1) Dominion interprets the wording “confirming acceptance” to mean that there are no major disagreements and that generally the methods between entities are acceptable using industry protection practices even if different protection setting philosophies’ exists. 2) If parties do not respond with a review of changes, confirming acceptance becomes burdensome. In the event that confirmation of acceptance of the changes is not received by the initiating party they should be allowed to proceed once the 90 days, or mutually agreed upon response time, has expired. Failure to respond with confirmation of acceptance within the 90 days, or mutually agreed upon response time, can be considered as confirmation of acceptance. The initiating party should not be restricted from applying appropriate settings due to the lack of acceptance confirmation from the other entity.
Response: Thank you for your comment and support.		

Organization	Yes or No	Question 4 Comment
1. The drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues. 2. The drafting team believes that any conflict resolution should be handled through normal business practices.		
ReliabilityFirst	Yes	ReliabilityFirst abstains and offers the following comments for consideration: 2. Requirement R4 Violation Severity Level a. During the previous comment period, ReliabilityFirst recommended that VRF for R4 be changed to “High” since this is dealing with interconnection protection systems. The SDT response by indicating they “...believes the VRF for Requirement R4 more aligns with the NERC criteria for a medium risk. “ After reading the NERC criteria for a medium risk, ReliabilityFirst would agree only if the Time Horizon of this requirement is changed to “Long Term Planning”
Response: Thank you for your comment. **The drafting team believes that the Time Horizon for Requirement R4 is assigned correctly at “Operations Planning” and also believes the VRF of “Medium” is correct. No changes were made.**		
PPL Corporation NERC Registered Affiliates	Yes	There is no clear responsibility in the standard if both parties cannot confirm acceptance.
Response: Thank you for your comment and support. **The drafting team believes that any conflict resolution should be handled through normal business practices.**		
Independent Electricity System Operator	Yes	We agree with the intent of the proposed changes, but believe some editorial changes are necessary for more clarity. We suggest the following wording for the SDT’s consideration: 1. “Confirm with the owner(s) of each Facility associated with the affected Interconnected Element that it accepts (or acceptance of) the resulting

Organization	Yes or No	Question 4 Comment
		Protection System(s) changes.” 2. In fact, Part 4.1 could also be worded to add clarity:”Within 90 calendar days after receipt of the proposed Protection System(s) changes,”

Response: Thank you for your comment and support.

1. **Based on stakeholder comments, the drafting team revised Requirement R4, Part 4.2 to read: Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.**
2. **The “receipt” in Requirement R4, Part 4.1 is referencing the summary results of the Protection System Coordination Study. The drafting team believes this is clear and unambiguous and declines to make the suggested change.**

Organization	Yes or No	Question 4 Comment
Western Small Entity Comment Group	Yes	
Imperial Irrigation District (IID)	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
GP Strategies	Yes	
Luminant	Yes	
seattle city light	Yes	
Florida Municipal Power Agency	Yes	
Certain Members of the ISO RTO Council	Yes	

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	
JEA	Yes	
US Bureau of Reclamation	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
pacificorp	Yes	
Western Electricity Coordinating Council	Yes	
Dynegy	Yes	
American Transmssion Company, LLC	Yes	
Essential Power, LLC	Yes	
American Electric Power	Yes	
Liberty Electric Power LLC	Yes	
Public Service Enterprise Group	Yes	
Ameren	Yes	
Tacoma Power	Yes	
Entergy Services, Inc. (Transmission)	Yes	

Organization	Yes or No	Question 4 Comment
City of Austin dba Austin Energy	Yes	
ITC	Yes	
Idaho Power Co.	Yes	
Sacramento Municipal Utility District	Yes	
Exelon Corporation and its affiliates	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
NV Energy	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.

Response: Thank you for your comment.

The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly

Organization	Yes or No	Question 4 Comment
based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise some of the VSLs.		

5. **The requirements and associated measures were modified to indicate that information was 'provided' instead of 'demonstrating that each affected entity received notification.' Do you agree with this change? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration:

Some commenters identified that a few of the Measures did not synch up with the Requirements. The drafting team made the measures consistent with the Requirements. Some commenters noted that the format of the verbiage in several similar Measures was not consistent. The drafting team made the format consistent.

Several commenters asked about revisions to PRC-001. The drafting team noted several things related to this:

- The drafting team did not modify the purpose.
- The Applicability section was updated to clarify which Protection Systems are applicable to Requirement R1. (The 'Facilities' portion of the Applicability section is identical to the new stakeholder-approved and NERC Board of Trustees-adopted PRC-005-2.)
- The drafting team did add Measure M1, which reads: "For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel."
- The drafting team recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database..

A few commenters had questions about the 'agreed to time frames' provide in the standard. The drafting team noted that an agreed upon schedule is the schedule all involved parties agree to. In most cases, the drafting team believes the mutually agreed upon schedule would be of a longer time frame than the maximum days specified in the requirement; however, entities are free to agree to an earlier timeframe.

A few commenters wanted clarification on which Protection Systems were subject to the requirements of the standard. The drafting team stated that the relays to be considered are identified in the Facilities Section of the standard, which reads: "Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements." The conditions under which the Protection System Coordination Study is performed are dependent upon the owner's philosophies and practices. The drafting team recognizes that philosophies and practices may vary from owner to owner, and that is why it is important to share the results of studies with the other owners.

A few commenters pointed out that, in some cases, fault current variations do not impact coordination. The drafting team noted that Requirement R2 was revised to allow a technical justification demonstrating why Fault current does not affect the Protection System coordination.

A few commenters expressed concerns about entities needing to document that the other entity had received the notification. The drafting team noted that Requirement R4, Part 4.1 was modified as follows: Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Coordination Study (per Requirement R1, Part 1.2) and respond to the other owner(s): Accepting the results, or Rejecting the results, and suggesting modifications to resolve any identified coordination issues.

Several commenters noted the need for a conflict resolution process. The drafting team responded that any conflict resolution should be handled through normal business practices. Measure M9 (now M10) was modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted. The drafting team believes the requestor cannot be held accountable when the other party does not respond.

Several commenters requested changes in the flow chart and/or examples. The drafting team corrected errors in the flow chart and updated the examples and diagrams based on comments.

Several commenters had questions about the term “interconnected bus”. The drafting team noted that the diagrams were revised to clearly indicate the drafting team’s meaning of interconnected bus.

There were various grammatical suggestions for improvement in this section. The drafting team considered them all and made many of the suggested changes.

Organization	Yes or No	Question 5 Comment
ACES Standards Collaborators	No	(1) The measures do not match the requirements. For example, R4 requires entities to confirm acceptance, which would demonstrate that each affected entity received notification. Again, the drafting team is using synonyms that produce the same result as the prior draft. To show evidence that the

Organization	Yes or No	Question 5 Comment
		information was "provided" would have to be some sort of notification of receipt. (2) Does the drafting team intend further actions for coordination beyond providing the studies to applicable entities? (3) We recommend the drafting team develop an RSAW to better explain how compliance would be measured against this standard. Thank you for the opportunity to comment.
Response: Thank you for your comment. 1. **The drafting team intends that information is "provided" (synonymous with "sent") and receipt of delivery is not required.** 2. **Yes, the drafting team intends for the receiving entity to review the Protection System(s) changes and identify any coordination issues.** 3. **The drafting team agrees with this approach and will work with NERC Compliance staff to develop an RSAW.**		
Independent Electricity System Operator	No	(1) We do not have a strong view one way or the other with respect to "provided" versus "demonstrating". However, the wording used among Measures needs to be consistent. For example, in M1 the wording is "Acceptable evidence for Requirement R1, Part 1.1 and its subparts, Parts 1.1.1. and 1.1.2, and 1.1.3 is a dated Protection System Study, or the summary results of..." seems reasonable since it shows the examples for "acceptable evidence". The examples listed illustrate what constitute "acceptable evidence". However, in M2, the wording "Acceptable evidence for Requirement R1, Part 1.2 demonstrating that the summary results of each Protection System Study (hard copy or electronic file formats) was provided...." Does not illustrate what constitutes "acceptable evidence", thereby leaving that to interpretation. We suggest M2 (and M4) be reworded along the same line as that for the other Measures (M1, M3, M5 to M9). (2) The Comment Form does not have a question on "Do you have any other comments?" Therefore, we are submitting the following comment under this

Organization	Yes or No	Question 5 Comment
		Question. We reiterate our concerns previously expressed with respect to PRC-001:We do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the "Mandatory and Enforceable Sections of a Standard". d. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. However, leaving this not measurable and unnecessary requirement in PRC-001-3 is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT could have proposed a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee's advice/direction for appropriate actions. The SDT's response to our previous comment was "This subject is outside the scope of this drafting team; however, your comment will be forwarded to NERC staff." We do not believe that the staff has brought this to the Standards Committee's attention. Note that the Standards Committee is responsible for managing the

Organization	Yes or No	Question 5 Comment
		standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. Once again, we urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.
Response: Thank you for your comment. **1. The drafting team modified the Measures to address your comment.** **2. The drafting team made several modifications to PRC-001, including the addition of Measure M1, which reads: "For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel." The drafting team also recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.**		
seattle city light	No	Because there is no "other comments" section included in this comment form, the following comments about the timelines for specific actions are appended here. 1. (R3.2) "Data Requests . . . . 30 Days or agreed to schedule' Seattle requests that "agreed to schedule" be clarified, in particular the limits in determining this schedule. If no further clarity is added, Seattle suggests that "or agreed to schedule" simply be deleted. 2. (R2.1) Short Circuit Study . . . . . . 24 months SCL recommends that the time line of 24 months be removed and that the 10% change in fault current criteria serve as the replacement for this requirement. 3. (R4.1) "Review PS Study . . . . .90 Days or agreed upon schedule" Seattle is concerned that, depending upon the complexity of the study, a lot of back and

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>forth communication between the utility entities may be required.

4. Please clarify

a. if each response to, or revision of the study trigger another 90 day review period and

b. the limits as the defining an "agreed to schedule." If no further clarity is added regarding agreed to schedules, Seattle suggests that "or agreed to schedule" simply be deleted.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1. The drafting team intends that an agreed upon schedule is the schedule all involved parties agree to. In most cases, the drafting team believes the mutually agreed upon schedule would be of a longer time frame than the maximum days specified in the requirement; however, entities are free to agree to an earlier timeframe.
2. Since the 10% threshold cannot be determined unless the study has been done, the drafting team believes it is appropriate for there to be a requirement to do the study. Note: the time frame has been changed to 60 calendar months.
3. The 90 days or the agreed upon schedule only pertains to the initial review and response of the Protection System Coordination Study. The drafting team realizes that there could be a lot of back and forth after the initial review and response but there is no associated time frame.
4a. Technically, your statement could be correct; however, the drafting team believes both parties will have an incentive to complete the process as soon as practical.
4b. The drafting team intends that an agreed upon schedule is the schedule all involved parties agree to. In most cases, the drafting team believes the mutually agreed upon schedule would be of a longer time frame than the maximum days specified in the requirement; however, entities are free to agree to an earlier timeframe.</td></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>1. BPA believes that the requirements and measures are onerous and should be eliminated. The change in wording is irrelevant.

Additional Comments

2. R1.1 requires a protection system study to be performed, but does not explain what is required for a protection system study.R1.2 lists some minimum requirements of a protection system study, but leaves many unanswered</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		questions, for example: Which relays must be included in the study? Where are the faults to be applied? What contingencies should be applied for the study? How many buses back into the system must be reviewed? 3. R1.1.2 introduces the term “interconnecting bus” with no definition of what it is. 4. R2 is a requirement that pertains to each facility associated with an interconnected element. The use of the word “associated” is too vague and leaves the interpretation of this requirement wide open. 5. In R2, the need to perform a new protection system study is based on a 10% or greater increase in fault current. Since many relays are based on impedance or differential methods, the value of fault current has no bearing on their need for a coordination review. R2, therefore, results in an unnecessary and useless burden when applied to elements protected with these relays.

Response: Thank you for your comment.

1. **The drafting team believes the requirements and measures support the reliability intent of the standard.**
2. **The drafting team believes the relays to be considered are identified in the Facilities Section of the standard which reads: “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.” The conditions under which the PSCS is performed are dependent on the owner’s philosophies and practices. The drafting team recognizes that philosophies and practices vary depending on the owner and that is why it is important to share the results with the other owners.**
3. **Based on your comment, the drafting team has designated the interconnecting bus in the example figures to provide clarity.**
4. **The drafting team believes the word “associated” in the context used is clear.**
5. **The drafting team revised Requirement R2 to allow a technical justification explaining why Fault current does not affect the Protection System coordination.**

Organization	Yes or No	Question 5 Comment
Florida Municipal Power Agency	No	First, there should be an “any other comments” question. Seeing that there isn’t one, we are adding our other comments here. 1. R3 - There should be thresholds of change to the bullets. For instance, changing the no-load tap changer of a GSU does minimally change the impedance of the GSU). transmission line neighbor installing a long chain link fence along the ROW will have a minimal impact on mutual coupling. These minimal changes do not require redoing the study, so, what percentage change in impedance requires redoing the study?
Response: Thank you for your comment. **The drafting team believes that information about any change (pursuant to Requirement R3, Part 3.1) that requires modification of an entity’s short circuit model should be provided to other Protection System owners associated with the Interconnected Element.**		
Imperial Irrigation District (IID)	No	IID believes the affected entity need to demonstrate it received notification.
Response: Thank you for your comment. **Based on yours and others comments, R 4.1 has been modified as follows: Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a Protection System Coordination Study (per Requirement R1, Part 1.2) and respond to the other owner(s): Accepting the results, or Rejecting the results, and suggesting modifications to resolve any coordination issues.**		
Nebraska Public Power District	No	Measurement 9 for R4 requires confirmation of acceptance prior to implementation of any planned protection system changes. This appears to be similar to ‘demonstrating that each affected entity received notification.’ The concern is holding one company responsible for actions of another that is not under the requestor’s control. It is recommended that there be clarification that if the requestor does not get confirmation of acceptance in the proper time line

Organization	Yes or No	Question 5 Comment
		then the requestor is not accountable or subject to violations. Another option is to remove R4.2.
Response: Thank you for your comment. **The drafting team believes that any conflict resolution should be handled through normal business practices. The old Measure M9 (new Measure M10) has been modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted. The drafting team believes the requestor cannot be held accountable when the other party does not respond.**		
CenterPoint Energy	No	Providing schedule information and project details by a transmission service provider to a generation entity may be governed by established, regional market rules that provide for what information can be shared with competitive entities. There are many installations in the ERCOT System where the owner of the interconnecting switchyard is not the same entity as the owner of the interconnected generation facility.
Response: Thank you for your comment. **The drafting team does not believe that the Transmission Owner is restricted in providing the Protection System data necessary for the Generator Owner to ensure proper coordination of the Protection Systems covered by this proposed standard.**		
Salt River Project	No	Receipt of confirmation should be required to confirm coordination.
Response: Thank you for your comment. **The old Measure M9 (new Measure M10) has been modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted.**		

Organization	Yes or No	Question 5 Comment
NextEra Energy	No	See page 19 of the redline PRC-027 Guidelines and Technical Basis. " System condition used in Protection System Studies include maximum generation with the transmission system under normal operating conditions and under single contingency conditions."Please clarify that "single contingency conditions" refers to breaker failure or protective system failure. It is not intended to mean single contingency operating conditions such as line or transformers out of service.
Response: Thank you for your comment. **The use of 'single contingency conditions' in this context is to indicate facility outages. e.g. line out.**		
Xcel Energy	No	Since the SDT did not provide a question for "any other comments", Xcel is using this question for that purpose. 1) We would appreciate some additional clarity as to what transmission fault conditions need to be evaluated by the Generator Owner. Figure 2 does not apply to very many of our units (on most, Breaker A would not exist and Breaker C is part of a breaker-and-a-half scheme). Is the generator supposed to evaluate only faults on the line between the GSU Transformer and the substation or evaluate his protection settings for a fault on any of the transmission lines leaving the substation? 2) Can the drafting team, either as part of the Application Guideline or in a separate document provide a list of protective functions the Generator Owner needs to evaluate or is it the complete suite of protective functions defined in the NERC SPCS Generator - Transmission Protection Coordination Guideline? 3) Requirement 3.1 is onerous as it requires notification for an open ended "when the proposed change modifies the conditions used in the coordination of Protection Systems." The requirement should be limited and instead provide a simple list of element changes that generally affect coordination with adjacent

Organization	Yes or No	Question 5 Comment
		Elements. 4) Similarly for 3.3, we recommend that this be modified to limit the scope to only changes that result in a change of performance or ratings. For example, settings that change the alarm conditions for a device or a "like-for-like" replacement should not be required to be communicated. Communicating every change would not improve reliability and would instead deter valuable resources to unnecessary compliance evidence activities.

Response: Thank you for your comment.

1. **In the situation cited, the Transmission Owner would review the data to ensure there are no coordination issues with the settings provided by the Generator Owner. Conversely, the Generator Owner would be responsible to ensure the settings provided by the Transmission Owner for breaker B does not result in coordination issues with generation Protection Systems. Example: that a Transmission Owner back-up relay does not operate before a Protection System designed to isolate a station service bus.**
2. **The drafting team has decided not to reference the subject document; however, the drafting team recognizes that it would be a good reference.**
3. **The drafting team believes that the bulleted items in Requirement 3, Part 3.1 provide the 'list' suggested.**
4. **The drafting team believes that although these circumstances will be rare, the noted information should be shared with the other entity so that they can update their records and provide any needed feedback.**

Organization	Yes or No	Question 5 Comment
City of Austin dba Austin Energy	Yes	(1) Austin Energy (AE) notes an inconsistency in R1.1.3 and the flowchart on page 22 of the clean version of Draft #2. R1.1.3 states that a Protection System Study is required "according to an agreed upon time frame" whereas the flowchart on page 22 says "perform the PSS within 6 months." AE asks the SDT to update the flowchart to match the requirement language. (2) AE believes the VSLs for R4 are not consistent with the language of the standard, specifically R4.1 and R4.2. For example, the Severe VSL language should read "The responsible entity reviewed the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and responded as to whether further action is required, all per R4, Part 4.1, but was

Organization	Yes or No	Question 5 Comment
		late by more than 30 calendar days. OR The responsible entity failed to review the summary results of a Protection System Study, as described in Requirement R1, Part 1.2, and respond as to whether further action is required, all per R4, Part 4.1. OR The responsible entity failed to confirm acceptance of any resulting Protection System(s) changes prior to implementing any planned change(s) associated with Requirement R3, Part 3.1 per R4, Part 4.2." AE is concerned about the current VSL language because it indicates the need to confirm acceptance of planned changes (e.g., new installation) instead of the resulting Protection System(s) changes.
Response: Thank you for your comment. **1. Based on your comment, the flowchart has been revised.** **2. The VSLs have been revised to match the revised requirements.**		
Dominion	Yes	1). Please replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places it appears in Figure 3. This proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 2). Dominion respectfully disagrees with the SDT feedback comment on Draft 1 where it was recommended to remove references from one Requirement to another Requirement. Dominion was not challenging consistency with the recommendation but were stating the need to simplify the wording in the standard. Each Requirement can stand on its own without the additional Requirement reference. By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement due to the fact that that it causes you to read between Requirements. Isn't this the purpose of the Process chart in the guidelines? 3). Under R1 - MI measure wording does not read as a completed statement.

Organization	Yes or No	Question 5 Comment
		Dominion suggests removing 'that' from the first sentence to "....demonstrating time frames". 4). Dominion respectfully disagrees with the SDT feedback that in R2 the term "deviation" is synonymous with "change". Deviation refers to variation from a standard, norm or mean. This is not a statistical calculation but a simple measure of change 5). In R3- 3.2, there appears to be a formatting issue. Any Requirement that references a calendar day is worded where the Calendar date is at the beginning of the statement; for example R3- 3.3. Need to change wording in R3- 3.2 for consistency throughout document to read "Within 30 calendar days of receiving a request or according to an agreed upon schedule, requested information related to coordination...."). 6) In Draft #1 Dominion wrote: "Throughout this Draft 1 of the standard, there are references that illustrate documentation requirements that are inconsistent. Recommend all be written as "(hard copy or electronic file formats)". The SDT responded saying "Each measurement in the standard (M1 through M10) has as evidence the statement "dated documentation (hardcopy or electronic file formats)." This is not the case; the point was that M1 reads "either in hardcopy or electronic file formats". This is minor but needs to be changed for consistency.

Response: Thank you for your comment.

1. **The drafting team used the term 'detect Faults on the BES Transmission System' to indicate those Protection Systems that may require review with other owners Protection Systems. The drafting team revised the phrase to read "installed for the purpose of detecting Faults on BES Elements" for consistency with the Facilities section of the Applicability. It is also noted that the identified interpretation was for the term 'transmission Protection Systems' which is not used in this Standard. Figure 3 has been modified to provide consistent language.**
2. **The drafting team still believes the references to other requirements in the standard are the best way to both maintain consistency and to describe the requirements. This approach has been approved through the Quality Review process and is**

Organization	Yes or No	Question 5 Comment
used in other NERC Reliability Standards. **3. Measure M1 was revised based on your comment.** **4. The drafting team made the suggested change.** **5. The drafting team believes Requirement R3, Part 3.2 is appropriate as written.** **6. The drafting team made the suggested change.**		
Western Small Entity Comment Group	Yes	The comment group has no comments regarding this question. This form provides no general comment area, so we are providing our additional comments here. We referenced the WECC Position Paper in the last round of comments, but now see that WECC did not submit comments. We urge the SDT to take a look at the paper. We received our copy from steve@wecc.biz . We can also forward a copy if an email address is provided. For the team's convenience, here is the relevant text: "WECC staff and WECC subject matter experts have reviewed the proposed standard and agree with the purpose of the standard. WECC staff and WECC subject matter experts agree that Protection Systems must be coordinated. However some subject matter experts believe that the proposed standard requires more documentation than is necessary and that the requirement to provide a hard copy or an electronic copy of each Protection System Study is administratively burdensome and not reflective of the intent of Results Based Standards. These subject matter experts believe that evidence that studies are coordinated and that entities have agreed to the results of System Protections Studies is adequate." We see that the SDT responded to Salt River Project's and other's similar concerns regarding hard copies by stating that that only summaries are needed, but we still see the standard as overly burdensome compared with the possible benefit. Tennessee Valley Authority, Dominion Power, Southwest Power Pool, the Nebraska Public Power District, Dairyland Power Cooperative, the Bonneville Power Administration, and the SERC Protection and Control Subcommittee provided some specific suggestions to reduce documentation burden which were all rejected. We urge the SDT to review these recommendations again.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **The drafting team believes the requirements in the standard accomplish the reliability objective of this standard and are not overly burdensome.**		
Duke Energy	Yes	Additional comment: R2.1.1 refers to “maximum available Fault current values”, but it’s unclear from the requirement or the Guidelines and Technical Basis how “maximum” is defined. We believe it should be maximum generation and all Facilities in service.
Response: Thank you for your comment. **The drafting team has included in the Guidelines and Technical Basis section the following which it believes answers this question: ‘These studies are typically performed assuming maximum generation and all Facilities in service.’**		
Tacoma Power	Yes	Additional Comments: 1. Why is there a version 4 for PRC-001 (under Version History) when the standard being balloted is version 3 (PRC-001-3). 2. PRC-027-1 does not appear to impose any requirements as to how quickly issues identified in a Protection System Study are addressed. It may be difficult to impose such a timeframe since some issues may just require a relay setting change, while others may require more drastic scheme modification, including design, procurement, installation, and commissioning. Perhaps requirements could be added to develop, within a specified timeframe, and then implement a mutually agreeable Corrective Action Plan. As written, it appears that an entity can be compliant with Protection System Studies that always indicate existing coordination issues, which does not completely achieve the purpose of the standard. Without a mechanism to close the loop, PRC-027-1 appears to require a lot of documentation and coordination without any guarantee that

Organization	Yes or No	Question 5 Comment
		existing coordination issues will ultimately be resolved. R4.1 really only requires entities to come to terms on the Protection System Study, but does not explicitly require any other course of action on existing coordination issues. 3. In M1, the sentence ending in "...demonstrating that the time frames specified in Parts 1.1.1 and 1.1.2" in a fragmented sentence. Also, should this sentence have "and 1.1.3" at the end? 4. M2 is a fragmented sentence. 5. M4 is a fragmented sentence. 6. As written, it may be difficult to audit parts of R3.1. Some of the language seems to be subjective and implicitly left to engineering judgment. a) First, it is not completely clear what the drafting team intended by the wording "associated with" or how an auditor might interpret that wording. b) Second, please consider changing "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)" to "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s), as stipulated in the existing Protection System Study." This should make it easier to audit this aspect of R3.1. c) Third, regarding the second through fourth bullets, engineering judgment will be required to determine when impedances need to be changed. For example, minor modifications could be made to a transmission line that, in a purely academic sense, could change the impedance; however, an entity may opt not to update the impedance based upon engineering judgment that the change is not significant to the impedance model. 7. For emphasis, under R3.2, considering changing "...within 30 calendar days of receiving a request or according to an agreed-upon schedule" to "...within 30

Organization	Yes or No	Question 5 Comment
		calendar days of receiving a request or according to an agreed-upon schedule, which may be longer or shorter than 30 calendar days." 8. R4.2 does not seem to explicitly require that a Protection System Study be completed before implementing changes indicated in R3.1, only that the changes are accepted. 9. R1.1.3 seems to suggest that the Protection System Study must be completed prior to implementation. However, according to the flow chart, it appears that a Protection System Study could be produced (in theory) six months after the changes were made. Furthermore, the flow chart applies the six-month timeframe even to R1.1.3, which does not match the text in R1.1.3.

Response: Thank you for your comment.

1. **Thank you for pointing out this mistake. The drafting team made the correction.**
2. **The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements. Requirement R4, Part 4.1 requires entities to 'respond as to whether any coordination issues were identified through a review of the summary results of a Protection System Coordination Study and if any further action is required'. The drafting team believes any coordination issues discovered through the periodic review will ultimately be resolved by the Protection System owners at the Interconnected Element.**
3. **The drafting team made the correction.**
4. **The drafting team made the correction.**
5. **The drafting team made the correction.**

6a. The drafting team made a change to the Guidelines and Technical Basis for Requirement R3 to clarify what is meant by the term 'associated with'. It now reads: "The drafting team recognizes that Facility changes at other locations can impact the Protection System Coordination Study of the Facility associated with the Interconnected Element; e.g., the addition of a large autotransformer bank or generator not directly connected to the Interconnected Element."

6b. The drafting team believes the existing wording is sufficient and declines to make the suggested change.

6c. The drafting team added the following language to the Rationale box for Requirement R3: "The drafting team believes that information about any change (pursuant to Requirement R3, Part 3.1) that requires modification of an entity's short circuit model should be provided to other Protection System owners associated with the Interconnected Element." The language

Organization	Yes or No	Question 5 Comment
contained in the Rationale box will remain as part of the standard. 7. The drafting team believes the existing wording is sufficient and declines to make the suggested change. If the time frame is shorter than the minimum 30 days, there would be no need to be 'agreed upon'. 8. Requirement R1, Part 1.1.3 requires that a Protection System Coordination Study be performed "according to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1 or Part 3.3". Requirement R4, Part 4.2 requires confirmation that other owners of each Facility associated with the affected Interconnected Element have completed a review of the Protection System changes and any identified coordination issues were resolved prior to implementing any proposed change(s) associated with Requirement R3, Part 3.1. 9. The drafting team revised the flowchart to indicate that a study must be performed before any changes are made. The flowchart was also modified to reflect that the 6 month timeframe is not associated with Requirement R1, Part 1.1.3.		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with question 5, we have the following general comments: (1) M1 - The word 'that' in the third line should be deleted and we believe that the words 'is dated documentation' are missing after 'Acceptable evidence for Requirement R1, 1.2. (2) M3 - For consistency, the word 'formula' should be replaced with calculation in Requirement R2, 2.1.2. (3) M4 - For clarity and consistency with the other Measures, we suggest rewording the opening sentence to read 'Acceptable evidence for Requirement R2, Part 2.2 is dated documentation (hard copy or electronic file formats) demonstrating that the updated Fault current values were provided within....'. (4) M5 - The wording of this section does not match the wording of the requirement. The words 'in hard copy or electronic file formats' should follow the word summary, not after the word settings.
Response: Thank you for your comment. 1. The drafting team made the suggested changes in Measures M1 and M2. 2. Measure M4 (old Measure M3) has been modified to include the following: determined by the equation.		

Organization	Yes or No	Question 5 Comment
3. The drafting team made the suggested change. **4. The drafting team made the suggested change.**		
Sacramento Municipal Utility District	Yes	Although this is unrelated to Question 5 there was no other space allocated for the for “any other comments.” While this is most likely a clerical error, we feel it is not appropriate to post a standard without making such a question available.
Response: Thank you for your comment. **The standards development process does not require a ‘catch-all’ question be included in every posting of a draft standard. The drafting team asked specific questions in order to gather specific answers to those questions.**		
American Electric Power	Yes	Because the comment form provides no section to provide “general comments”, AEP offers them below. AEP would like to inform the drafting team that our negative vote on this standard is primarily driven by A) the lack of clarify in regards to its scope (as discussed in the response to Q2) and B) the timeframe allotted to perform the Protection System Study (as discussed in the response to Q3). C) It would be more appropriate for R 1.1.1 to be included in the implementation plan, rather than embedded within the standard itself. D) The proposed standard is difficult to follow, in the way that it jumps back and forth among requirements. We would encourage any changes which might increase the readability of the proposed standard.
Response: Thank you for your comment. **A) The drafting team believes that the Applicability section regarding Facilities adequately describes which Protection System**		

Organization	Yes or No	Question 5 Comment
components need to be coordinated between entities. B) Based on stakeholder comments, the drafting team revised the timeframe for Requirement R1, Part 1.1.1 to 60 calendar months. C) The drafting team agrees your suggestion provides one way of addressing the requirements to have documented Protections System Coordination Studies for each Interconnected Element. However, the drafting team believes the structure of Requirement R1, Part 1.1.1, as currently written, achieves this goal. Further, NERC performs periodic review of standards and the requirement can be removed at that time, if appropriate. D) The drafting team believes the revised 'draft 3' of the standard is more readable.		
ITC	Yes	1. Figures 1-5 designate a preferred responsibility of coordination on either entity which contradicts with intent of R3. R3 details all the changes which must be provided to the adjacent utility, seemingly so they can coordinate their protection over yours. However, Figures 1-5 place the coordination responsibility on the utility which does not own the Protection System. I agree that R3 should remain almost as-is. However, the coordination responsibilities in Figures 1-5 should be reversed or preferably removed. Owner R should be responsible for coordinating Breaker A relays. Only the owner should be responsible for coordinating this relay. 2. SDT needs to define the term "interconnecting bus" and perhaps identify the interconnecting bus in Figures 1-5. 3. In Figures 1-4 the Interconnected Element is a line.
Response: Thank you for your comment. 1. The Figures and associated processes are examples of options that may be used to achieve coordination and are not intended to be all inclusive. The drafting team believes the owner proposing changes in Figure 5, e.g. Transmission Owner S, would not necessarily have the Protection System information and setting to ensure that coordination will be achieved; therefore, the procedures noted for Figure 5 ensure that Transmission Owner R and Generator Owner T can verify that changes made by Transmission Owner S can be coordinated. The drafting team believes the Figures do not contradict the intent of Requirement R3. 2. Based on your comment, the drafting team has designated the interconnecting bus in the example figures to provide clarity.		

Organization	Yes or No	Question 5 Comment
3. As noted in Figure 4 above, the Interconnected Element between the Transmission Owner and the Distribution Provider is the transmission line or tap between the line and Breaker C.		
FirstEnergy	Yes	FirstEnergy supports the change described by Question 5. Other comments from FirstEnergy in addition to the specific questions asked by the drafting team: A) PRC-001-3 EFFECTIVE DATE: The PRC-001-3 standard needs to be edited to match what is stated in the Implementation Plan. The Implementation Plan indicates that both PRC-027-1 and PRC-001-3 will become effective at the same time which is stated as being the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. However, the PRC-001-3 standard in its Effective Date section indicates the first day of the first calendar quarter twelve months following applicable regulatory approval. B) PRC-001-3 VERSION HISTORY: The Version History of the PRC-001-3 standard needs some clean-up. The table reflects a "version 4" however this project creates version 3. Looks l+A74ike the fix is to delete the row labeled version 3 and change the version 4 to reflect 3. The description text in that row is correct. C) PRC-001 VERSION CHANGES: NERC needs to consider what it plans to do with the existing NERC BoT Approved versions PRC-001-1.1 and PRC-001-2 which have yet to be filed with FERC. It is recommended that NERC suspend the filing of those standards, keep it simple and file PRC-001-3 with this project. This will avoid undo industry confusion and transition. D) PRC-001-3 MISC CLEAN-UP: Section D, Part 1.1 revise Compliance enforcement authority" to read "Compliance Enforcement Authority (CEA)". This is a defined glossary term and is shown capitalized in other areas of the standard. In the second sentence, capitalize "entity" in the reference to "Regional entity".

Organization	Yes or No	Question 5 Comment
		E) PRC-001-3 R1: Seems odd to have a standard with only one requirement. The requirement states "Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area." FE proposes that R1 or an alternate be moved to PER-005.
Response: Thank you for your comment. **A) The drafting team made the change to the Effective Date language.** **B) The drafting team made the change to the Version History.** **C) Based on the projected approval date of this Standard your suggestion may not be possible; however, this will be investigated based on the results of the next posting.** **D) The suggested change has been made.** **E) The drafting team did add Measure M1, which reads: "For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel." The drafting team recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.**		
National Grid and Niagara Mohawk (A National Grid Company)	Yes	National Grid offers the following additional comments that do not pertain to Question 5. The comments are included here since the Comment Form did not have an additional question concerning if we had additional comments. 1. Page 4: Other Aspects of coordination of Protection Systems addressed by other Project needs to be included in the final standard since it delineates what is not included in this one. 2. Page 8: Para.R2.1.2 should be reworded as it allows for a series of increments in fault current each less than 10% but which when summed over a number of review periods could collectively exceed 10%. 3. Application Guidelines: a. Page 21: "Data used to determine Fault currents...." is essentially the short

Organization	Yes or No	Question 5 Comment
		circuit model and the associated data base of line, transformer and generator impedances and connections. If that what is expected then it should be so stated otherwise "data" leaves a lot open to the reader's conjecture. b. Page 25: Decision point regarding R2.1.2 has the same issue as identified above in comment 2. c. Diagrams Fig. 1, 2, 3, 4, 5: The text that goes with these diagrams is inappropriate in its assignment of responsibilities for who reviews what coordination and the change of wording from "verify" to "review" does not resolve this problem. It is a protection system owner's responsibility to coordinate their system with adjacent systems and it is the same owner's responsibility to model adjacent systems in sufficient detail to enable that owner to perform that coordination. 4. Fig . 2, 5: The text refers to "generator protection" which can mean a wide range of protection functions such as but not limited to those related to voltage, frequency, loss of field, over-excitation and more. These were excluded on page 4 of the standard and their exclusion here should be emphasized. 5. Fig. 3, Notes following figure 3 exclude reverse power as being a protection system installed to detect faults on the BES Transmission System. We disagree. In our system and other systems in NE reverse power was historically installed specifically to detect and clear backfeed to a faulted transmission system.

Response: Thank you for your comment.

1. Those are included in the Background Section of the standard and will remain in the BOT approved version of the standard.
2. The drafting team modified the Rationale box for Requirement R2 for clarification in response to your comment.
3a The drafting team revised the language by removing the phrase "Data used to determine Fault currents…" for clarification in response to your comment.
3b The drafting team revised the diagram for clarification.
3c The drafting team revised the Figures for clarification.
4. The drafting team revised the Figures and the text for clarification

Organization	Yes or No	Question 5 Comment
5. Per the note in the referenced figure, reverse power relays are 'often' installed for purposes other than that you describe. In your case where the reverse power relays are installed to provide the protective function, they should be included in the coordination review.		
Certain Members of the ISO RTO Council	Yes	NERC must continue to correct such requirements, as it is not the responsibility of the entity subject to a requirement to ensure another party acts.
Response: Thank you for your comment. The SDT modified the language to better clarify the intent.		
SERC Protection and Controls Subcommittee (PCS	Yes	Other comments (not associated with Question 5) are being provided which could not be addressed in the questions listed above: 1). R2 requires short circuit study every 24 months even though the SDT's own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace "detect Faults on the BES Transmission System" with "protect the BES Transmission System" in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it "has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements." Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity's Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively.

Organization	Yes or No	Question 5 Comment
		Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are confusing. 5). Under R1 - MI measure wording does not read as a completed statement. Suggest removing 'that' from the first sentence. 6) The process chart is a direct indication that this process and undertaking for entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, 'there is no evidence there is widespread miscoordination of protection systems.'

Response: Thank you for your comment.

1. **The drafting team does not see the direct correlation between the studies required in this standard and the noted studies in the TPLs. However, the drafting team revised Requirement R2 to 60 calendar months to align with Requirement R1.**
2. **The drafting team declines to make the suggested change; however the wording in the figure has been modified for consistency.**
3. **The drafting team revised the VSLs for Requirement R2.**
4. **The references that you indicate have been approved as appropriate way of accomplishing the objective of this standard.**
5. **The drafting team revised Measure M1 as you suggested.**
6. **The drafting team believes the requirements, as written, contribute to the reliability of the BES by requiring entities to**

Organization	Yes or No	Question 5 Comment
coordinate their Protection Systems associated with Interconnected Elements.		
Texas Reliablity Entity	Yes	OTHER COMMENTS (not responsive to any specific question asked above): 1. R2.2: We suggest a minor change "...indicates a deviation in ***single line to ground or 3-phase*** Fault current of 10% or greater ....” 2. R3.1: Based on recent work by the Protection System Misoperation Task Force (PSMTF), changes in logic settings should also be included (e.g. directionality V/Q logic, trip equations, carrier echo logic and coordination timers, carrier dip switch settings, etc.). We would suggest modifying the first bullet to say”...modification of: protective relays or protective function or logic settings, communication systems,....” 3. The SDT may also want to consider adding an item to the list - “Changes to the transmission system topology that change the equivalent impedance or fault current.”
Response: Thank you for your comment. **1. The drafting team made the suggested change.** **2. The drafting team believes the protective ‘logic settings’ used for Protection System coordination are included in the “protective function settings” and declines to make the suggested change.** **3. The drafting team believes that “Changes to the transmission system topology that change the equivalent impedance or fault current” would be captured by the periodic short circuit studies. The drafting team believes the second bullet addresses the situation as well, it reads: “Changes to a transmission system Element that alter any sequence or mutual coupling impedance.”**		
Georgia Transmission Corporation	Yes	Repeat of SERC PCS Other comments are being provided which could not be addressed in question 1 - 5 listed above: 1). R2 requires short circuit study every 24 months even though the SDT’s own rationale is that other requirements will trigger Protection System Studies first. Thus R2 increases burden on entities unduly, and we propose every 60 months consistent with TPL-001-2 draft 8 R2 2.6.1, which NERC has already filed for

Organization	Yes or No	Question 5 Comment
		FERC approval. We understand that TPL short circuit study may be for a different purpose but that purpose is of commensurate importance. 2). Please replace “detect Faults on the BES Transmission System” with “protect the BES Transmission System” in all three places it appears in Figure 3. Our proposed revised wording is consistent with the rest of the wording in your example Figure 3, the Figure 4 wording, and NERC Interpretation 2009-17 already approved by the industry. 3). VSL escalation in 10 days is not representative of the severity of the violation. The SDT correctly points out in R1 rationale that it “has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements.” Many entities have numerous Interconnected Elements, and recommend the percentage approach allowed within NERC guidelines, as more representative of violation severity. We propose percentage breakpoints of 5, 10, 15 and 20% of an entity’s Interconnected Elements being late for Lower, Moderate, High, and Severe Violation Levels, respectively. Specifically, Lower would apply to up to 5% so that even a single Interconnected Element would be a violation. 4). Throughout the 1st and 2nd draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.1.1, R2.1.2, R2-2.2, R4-4.1, R4-4.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. We appreciate the Drafting Teams perspective, but the SERC PCS believes that such cross references are confusing. 5). Under R1 - MI measure wording does not read as a completed statement. Suggest removing ‘that’ from the first sentence. 6) The process chart is a direct indication that this process and undertaking for

Organization	Yes or No	Question 5 Comment
		entities will be overwhelming. New systems will be required to track many details of timeframe requirements and communication dates. Additional resources will be required placing increased workload for an effort to change the process that already works for us when working with other entities. The Drafting Team indicated, 'there is no evidence there is widespread miscoordination of protection systems.'
Response: Thank you for your comment. 1. The drafting team does not see the direct correlation between the studies required in this standard and the noted studies in the TPLs. However, the drafting team revised Requirement R2 to 60 calendar months to align with Requirement R1. 2. The drafting team declines to make the suggested change; however, the language in the noted figure has been updated for consistency. 3. The drafting team revised the VSLs for Requirement R2. 4. The references that you indicate have been approved as appropriate way of accomplishing the objective of this standard. 5. The drafting team revised Measure M1 as you suggested. 6. The drafting team believes the requirements, as written, contribute to the reliability of the BES by requiring entities to coordinate their Protection Systems associated with Interconnected Elements.		
Idaho Power Co.	Yes	1. R1 The requirement is written to be applicable to Transmission Owners. In our case we have several lines where we do not own the Interconnecting Element, but operate the Protection System at one terminal. Based on the Glossary, we believe this makes us a Transmission Operator. If this interpretation is accurate, there would seem to be a gap in the Applicability of the Standard, as it does not include the Operator. 2. R2 We are wondering why this Requirement is only applicable to the Transmission Owner. Should it not be applicable to all the functional entities similar to the language used in R1, R3, and R4? General comments 3. In reviewing the Standard, there was confusion related to the Protection System Study and what the 10% was measured against. We believe that the

Organization	Yes or No	Question 5 Comment
		Protection System Study referred to in the Standard is that group of faults and contingencies used to create the in-service settings of the relay. Could this be clarified? 4. Additionally, the exchange of information between Functional Entities is a critical part of PRC-027, however, no mechanism is in place to ensure proper contact information is available. Employee movement within a utility may render contact information obsolete. In addition, Independent Power Producers, such as wind farms, are not typically staffed by local personnel or by individuals with a knowledge of System Protection. Because PRC-027 relies so heavily on the exchange of information it is not sufficient to simply place time lines on the transfer of data between Functional Entities. Additional controls to ensure that these data requests reach the appropriate people is needed.
Response: Thank you for your comment. **1. If you are a registered Transmission Owner and own the Protection System, you are responsible for the coordination of the Protection System.** **2. As noted in the Guidelines and Technical Basis section: In Requirement R2, the Transmission Owner is identified as the Functional Entity responsible for performing the Fault current studies because they maintain the data required to perform the studies. Generator data (including data provided by Distribution Providers) is incorporated into the Transmission Owners' short circuit models.** **3. The intent is that the 10% be measured against the Fault currents that were available at the interconnected bus at the time the last Protection System Coordination Study was done.** **4. The drafting team agrees that entities must have accurate contact information for this standard as well as the existing requirements in PRC-001 but ensuring contact information is kept current is beyond the scope of this standard.**		
Northeast Power Coordinating Council	Yes	We agree with the change. However, we are adding a comment on the VRFs. The VRFs should be High, not Medium. There are similar requirements in PRC-023-2 Transmission Relay Loadability, and TPL-001-2 Transmission System

Organization	Yes or No	Question 5 Comment
		Planning Performance Requirements which have a High VRF. Also, from the Justification for Proposed Violation Risk Factors and Violation Severity Levels in PRC-027-1 - Protection System Coordination for Performance During Faults, the FERC VRF G4 Discussion reads “Guideline 4- Consistency with NERC Definitions of VRFs: Failure to perform a Protection System Study for each Interconnected Facility to verify that Protection Systems coordinate such that the least number of power system Elements are isolated to clear Faults could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, it is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the Bulk Electric System, regardless of the situation. Therefore, this Violation Risk Factor level conforms to NERC’s definition of a Medium VRF.” Poor protection system coordination during a disturbance can create severe system conditions faster than Operators can respond to them, leading to system instability or a cascading failure. These circumstances are consistent with the NERC definition of a High VRF.
Response: Thank you for your comment. **The drafting team assigned the VRFs in accordance with the NERC criteria and FERC guidelines for establishing VRFs, and believes the assigned risk factors are appropriate.**		
Pepco Holdings Inc & Affiliates	Yes	We agree with this change. However, we have several other comments concerning this standard in addition to those expressed in response to Questions 1 thru 5. Usually there is a space on the comment form to enter these additional comments. Absent one, we offer these additional comments as an addendum to Question 5. 1) Requirement R2: The phrase “Facility associated with an” contained in R2 is confusing and unnecessary and should be eliminated. R2 should simply read “For each Interconnected Element on its System, the Transmission Owner

Organization	Yes or No	Question 5 Comment
		shall:" 2) Requirement R2, Parts 2.1.1 and 2.1.2: Remove the term "interconnecting bus" and replace it with the phrase "point of interconnection between the Entities." The point of interconnection between the entities is more descriptive in that the interconnection point may not be a physical "bus", but rather the terminals of a line disconnect switch, terminals of a breaker, specific transmission pole, etc. Even though the point of interconnection is often modeled in a short circuit program as a "bus", the term "interconnecting bus" has no physical meaning. 3) Requirement R3, Part 3.3: A footnote should be added stating that this requirement does not apply to those temporary setting changes that sometimes are applied during commissioning, maintenance, or investigative testing activities to verify performance of individual protective elements, provided the original settings were returned upon the conclusion of the testing activity. For example, in multifunction relays when testing backup time delayed protective elements (i.e., zone distance or time overcurrent elements) it may be necessary to temporarily disable high speed elements (i.e., pilot or zone 1 elements). 4) The SDT states that "the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays". However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. The mention of "the appropriate use of time delays in relays" in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped

Organization	Yes or No	Question 5 Comment
		(exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS's during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although we support the overall desire to ensure that protective systems are "properly coordinated"; we see little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry.The above comment was also submitted with Draft 1 of the standard. In their response the SDT stated that PRC-027 was being developed in response to FERC Order 693. However, Order 693 only directs NERC to address specific deficiencies in PRC-001 surrounding certain measures and levels of non-

Organization	Yes or No	Question 5 Comment
		compliance relating to the notification and response to the detection of failures in relay protection systems. As such, we believe PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. We urge the SDT to revisit FERC Order 693 and revise this standard as appropriate to address only the stated FERC directives.
Response: Thank you for your comment. 1. **The drafting team made the suggested change.** 2. **The drafting team considered this alternative previously; however the "point of interconnection between the Entities' can sometimes be at a given point on the line and in some cases neither entity may own the line itself. Therefore the present language was deemed sufficient.** 3. **The drafting team believes temporary settings changes are addressed in TOP-002, which incorporated Requirements R5 and R6 from PRC-001-1. Temporary settings applied (or changed) to perform maintenance testing of a relay would not have an effect upon overall coordination of the Protection System, as the relay would likely be taken out of service for such testing.** 4. **Although the drafting team does not necessarily disagree with your assessment of the language in the "Final Report on the August 14, 2003 Blackout in the United States and Canada" the drafting team does believe that the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the subject result, which identified the need to address "the appropriate use of time delays in relays," by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination. The drafting team is operating within the scope the approved SAR, which includes recommendations in addition to those in FERC Order 693, and declines to remove the reference to Recommendation 21C from the Background section of the draft standard.**		
Southern Company	Yes	1. We believe that the proposed standard is too prescriptive regarding the specific duties and multiple time frames of each of the parties TO,GO, and DP. Including time frames for each Interconnect Element with regard to effective dates (6 mo), initial studies (48 mo), studies triggered by change of equipment or change of fault current (6mo), TO/GO/DP agreed upon schedules (variable), delivery of studies (90 days) , short circuit studies (24 mo), notification to others of fault current changes (30 days), change detail notification (30 days), and review of summary results (90 days) is unnecessary and unduly burdensome. The process flow chart provided on page 22 of the draft standard is evidence of

Organization	Yes or No	Question 5 Comment
		the complexity of the proposition. Please seriously consider the following simplified three-requirement approach which will similarly accomplish the desired outcome of coordination of the Protection System for Interconnected Elements. R1). Require the two parties of the Interconnecting Element to jointly develop a Protection System Study- initially with X months to complete. R2). Require a review/update of the protection system study for proper coordination anytime a change to the system may upset coordination. R3). Require a review/update of the protection system study for proper coordination every X years. The corresponding measures for each proposed requirement could be... M1: has a protection system study been performed by the initial required date? M2: has a protection system study been reviewed/updated for system changes which impact the coordination? M3: has the protection system study been reviewed/updated every X years? During an audit period these requirements and measures will drive entities to establish and maintain protection system studies. This approach keeps the focus on the protection system study rather than the multiple actions with varying time frame restrictions. We believe that these changes will result in an equally effective driver to establish coordination while keeping the standard as succinct as possible. 2. In general, for protection on the transmission line leaving the plant, the generator owner should be responsible only for coordinating with the first set of line relaying encountered when proceding across the interconnecting element. He should not be responsible for coordinating with relaying at the opposite end of the interconnecting element. For example, in Figure 5 on Page 28 of the draft standard, Generator Owner T should not have to worry about a

Organization	Yes or No	Question 5 Comment
		review of the relaying located at breakers G, F, or E. Another example is Figure 2, Page 25 of the draft standard: Generator Owner R should not be responsible for reviewing the relaying at the breaker C.
Response: Thank you for your comment. 1. **The drafting team believes the standard, as written, is necessary to ensure the reliability objectives are met.** 2. **The drafting team agrees with your statement. Figure 5 is included for the unique situation that the owner of the interconnecting bus may not be the owner of the Protection System. The following note has been added to Figure 5: Note: In a large majority of cases, Figure 2 would be applicable for most generator interconnections. In Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T.**		
Southwest Power Pool Reliability Standards Development Team	Yes	
GP Strategies	Yes	
Luminant	Yes	
Hydro One Networks Inc.	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
JEA	Yes	
US Bureau of Reclamation	Yes	
Operational Compliance	Yes	
pacificorp	Yes	

Organization	Yes or No	Question 5 Comment
Western Electricity Coordinating Council	Yes	
Dynegy	Yes	
American Transmssion Company, LLC	Yes	
Essential Power, LLC	Yes	
Wisconsin Electric Power Company	Yes	
Liberty Electric Power LLC	Yes	
Public Service Enterprise Group	Yes	
Ameren	Yes	
Entergy Services, Inc. (Transmission)	Yes	
Exelon Corporation and its affiliates	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee	Yes	
NV Energy	Yes	
ATCO Electric		Additional comments from AE that does not fit any specific question: (1) Timelines: There are too many hard timelines that aren't consistent between

Organization	Yes or No	Question 5 Comment
		individual requirements (24 months, 6 months, 90 days, 30 days, agreed upon time frame, prior to implementation, etc.). Keeping track of these timelines and evidence gathering will take considerable time and effort. Can the drafting team reduce the amount of timelines to make this standard manageable? Can the drafting team anticipate how to audit this standard during the standard development process? (2) There are requirements referred to other requirements and vice versa. Can the drafting team not to refer the requirements back and forth? Can the drafting team anticipate how to audit this standard during the standard development process?
Response: Thank you for your comment. **1. The drafting team believes the timelines are necessary to ensure the reliability objectives of the standard are met. The drafting team can't anticipate audit procedures; however, members of the drafting team will be involved in the development of the RSAW.** **2. The drafting team can't anticipate audit procedures; however, members of the drafting team will be involved in the development of the RSAW.**		
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. Changes to the interconnection fault currents do not happen that fast and a 30 days delay does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: Thank you for your comment. **The drafting team assigned the VSLs in accordance with the NERC guidelines and the FERC Order on VSLs. The drafting team believes the coordination process requires entities to work individually and collaboratively, exchanging information and**		

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communicating in a timely manner. Each part of the coordination process is critical to success and the exchange of information provides the necessary situational awareness for coordination to occur. The drafting team's intent is to assign the VSLs accordingly based upon the significance of the individual requirement parts. Based on yours and others comments, the drafting team did revise some of the VSLs.		
Midwest Reliability Organization NERC Standards Review Forum		In addition to the previous comments outlined above, the NSRF offers the following comments for the drafting team's consideration. 1. Recommend the timeframes in R1.1.1 and R2.1 be stated in calendar years. The NSRF is concerned that a utility would be found in violation of this standard if one study was done in February of 2012 and the next one in March 2014 based on the current wording. The intent of a results-based standard is not to have these types of technicalities built into them. 2. An entity cannot study a part of the system that they do not own. The examples at the end of the draft in the Application Guidelines appear to imply that they should. Settings should be obtained from remote ends of a tie line only to be used in conjunction with studying the settings for which an entity has direct control. If an entity can't issue setting changes for a relay, then the entity can't study it to see what the settings should be. If both ends need adjustment then an iterative coordination back and forth between Entities should be performed. The majority of utilities would not feel comfortable accepting an external entity's settings changes for their own equipment. Recommend additional wording be added to the Application Guidelines to the further clarify the drafting team's intent. 3. R2, Part 2.1.1: Recommend R2, Part 2.1.1 be revised to only require short circuit values be 'studied' at buses for which the entity in question specifically owns. For Interconnected Facilities between two entities, fault current values should be 'requested' by the neighboring utility. This would be beneficial to ensure that both entities are comparing models to keep them as up to date as possible. Better yet are boundary equivalents as discussed in previous

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		comments. 4. R2, Part 2.2: Similar to our previous comment for R1, Part 1.2, the proposed language in Part 2.2 appears to indicate that internal Interconnected Elements would require additional documentation and notification beyond what is necessary. This should only be required of Interconnected Elements in which there are two or more owners. Proof of study should be adequate for internal situations. 2.2 Within 30 calendar days after identification where the calculation performed, pursuant to Requirement R2, Part 2.1.2, indicates a deviation in Fault current of 10% or greater, provide each owner of the Protection System associated with the Interconnected Element, that include two or more Registered Entities, the updated Fault current values (Iscs).
Response: Thank you for your comment. **1. The drafting team increased the timeframes for both requirement parts to 60 calendar months; however declines to make the suggested change to calendar years.** **2. The drafting team does not agree with the issue as stated. Settings obtained from remote ends of a tie line would be used to ensure no coordination issues exist with other setting on its system. If coordination issues are identified, then the drafting team agrees that it may be an iterative process for the two entities to come to a mutual solution.** **3. Requirement R2 has been revised. The drafting team believes that the Requirement R2, Part 2.1 indicates that the entity is conducting the study at their interconnecting bus: Perform a short circuit study to determine the present maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus.** **4. Requirement R2 has been revised. The drafting team believes that Requirement R2, Part 2.1 indicates that the entity is conducting short circuit studies only for their interconnecting bus(s).**		
PJM Interconnection		PJM supports revising the language in Requirement 1 of PRC-001 by replacing the term 'familiar.' This word is ambiguous and confusing in terms of the specific expectations of the applicable functional entities regarding the purpose and limitations of protection system schemes applied in its area.
Response: Thank you for your support.		

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The drafting team is not revising the language of the remaining requirement of PRC-001, but is providing a measure.		
ReliabilityFirst		ReliabilityFirst offers the following comments on the VSLs for consideration: 1. Requirement R3 VSL a. ReliabilityFirst believes VSL for Requirement R3 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." Requirement R3, Part 3.1 and 3.1 requires the entity to provide "details" and the associated VSLs references "information". ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement. b. It is unclear which requirement the last VSL under the "Severe" category is referring to. ReliabilityFirst recommends adding the Part number in which the VSL is associated with. 2. Requirement R4 VSL a. ReliabilityFirst believes VSL for Requirement R4, Part 4.1 is not meeting the intent of FERC VSL Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement." The VSLs associated with Part 4.1 use the language "confirmed acceptance" though the language in the actual Part talks about review of summary results and response as to whether further action is required. ReliabilityFirst recommends the SDT modify the VSL to be consistent with the language in the requirement as follows: "The responsible entity reviewed the summary results of a Protection System Study and responded as to whether further action is required per R4, Part 4.1, but was late by 10 calendar days or less"
Response: Thank you for your comment. **1a The drafting team made the suggested change.** **1.b The drafting team made the suggested change**		

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2.a. The VSL language has been modified to be consistent with the revised Requirement 4, Part 4.1.		
Consumers Energy		The following comments are unrelated to Question 5. However, there has not been a question/section added for other/general comments. 1) In the process flow chart (page 22) the R2.2 box which states "Within 30 days, provide each owner of the Protection System associated with the Interconnected Element", we believe the key element, "the updated Fault current values" was not included in this statement. 2) In reading the Example Process on page 23, we were expecting to be able to follow it through the process flow chart on page 22 as one possible example to guide you through the standard process. As it started off as a request for information, we assumed the flow process started in the R3 box "Data request" which indicates no further action. Yet the example process continues on. We would suggest an improved explanation paragraph be added to the "Example Process" to better clarify what the example is intended to illustrate.
Response: Thank you for your comment. **1. The drafting team revised the flow chart to be consistent.** **2. The drafting team revised the flow chart to be consistent.**		
ATCO Electric (AE)		Requirement R1.1.2 – A 10% change in fault current isn't much in some areas of AE's system, perhaps as little as a few hundred amps. This could lead to a burdensome requirement to frequently review the same areas of our system. Ten percent seems fairly restrictive when we typically use safety margins of 40% to 50% in selecting instantaneous overcurrent settings
Response: Thank you for your comment. **As noted in the Guidelines and Technical Basis section: The drafting team investigated various inputs that would trigger a review of the existing Protection System Studies and determined, through the experience of the drafting team members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an**		

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appropriate indicator that an updated Protection System Coordination Study may be necessary. In the situation that you described, the standard provides the entities the opportunity to 'technically justify why such a study is not required'. Also note that the requirement to conduct the review has been modified to 60 [calendar] months.		

END OF REPORT