Consideration of Comments on First Draft of System Protection Coordination Standard (Project 2007-06)

NOTE: This comment report was prepared in response to the initial posting of PRC-001-2 (09/11/09 - 10/26/09). These responses have been rendered moot by the development of the new draft standard PRC-027-1; they are posted here for process purposes only.

Background Information:

The SPC SDT responded to the comments from the initial posting of PRC-001-2 and incorporated pertinent suggestions into the second draft of the standard in the first quarter of 2010. This second draft went through a NERC Quality Review in December 2010 which resulted in substantial changes to the standard. After informal consultations with industry stakeholders, as well as NERC and FERC staffs, the drafting team decided to focus its knowledge and expertise on developing a new results-based standard with the stated purpose: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."

The first draft of PRC-027-1 is posted for stakeholder review and comment at the following site:

http://www.nerc.com/filez/standards/System_Protection_Project_2007-06.html

Consideration of Comments on First Draft of System Protection Coordination Standard (Project 2007-06)

The System Protection Coordination Standard Drafting Team thanks all commenters who submitted comments on the first draft of the System Protection Coordination Standard (Project 2007-06). This standard was posted for a 45-day public comment period from September 11, 2009 through October 26, 2009. The stakeholders were asked to provide feedback on the standard through a special Electronic Comment Form. There were 37 sets of comments, including comments from more than 95 different people from approximately 60 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

In this report the comments have been organized by question so that it is easier to see where there is consensus. All comments may be viewed in their original format at the following site:

http://www.nerc.com/filez/standards/System_Protection_Project_2007-06.html

Due to industry comments, the following modifications were made:

- System Protection Coordination definition – Revised to reference Table 1 - Steady State & Stability Performance Planning Events of the NERC Transmission Planning (TPL) reliability standards.
- Purpose – Clarified by adding the verbiage "between interconnected functional entities."
- Applicability – Revised the applicability as it pertains to Distribution Providers by removing the verbiage "or that interconnect with Generator Owners."
- Requirements (all) – Clarified language to allow for flexibility of timeframes by adding the verbiage "or according to an agreed upon schedule."
- Added new Requirement R2 requiring review of received data.
- With the addition of the new Requirement R2, the remaining requirements were incremented from R2 through R6 to R3 through R7. Note, references in the response to comments are for the original requirement numbers and not the new.
- Requirements R2 & R3 – Clarified determination of what changes not on the interconnected Facilities impact System Protection Coordination
- Requirements R2 & R3 – Revised language to be more specific regarding functional entity applicability
- Requirement R4 – Changed the VRF from "Medium" to "Lower"
- Attachments (all) – Revised verbiage regarding resolution process to eliminate references to Regional Reliability Organizations
- Attachments (all) – Added Step 7 to document changes made during commissioning that impact System Protection Coordination

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 of Standards and Training, Herb Schrayshuen, at 404-446-2563 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf

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

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<tr><td colspan="3">1. Rick Paschall</td><td>PNGC</td><td colspan="6">WECC</td><td colspan="4">3</td></tr>
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<tr><td colspan="3">3. the 12 member utilities of PNGC</td><td>PNGC</td><td colspan="6">WECC</td><td colspan="4">3</td></tr>
<tr><td>2.</td><td>Group</td><td>Paul Nauert</td><td>System Protection</td><td>X</td><td></td><td>X</td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td></tr>
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<tr><td colspan="3">1. AEGC</td><td></td><td colspan="6">RFC</td><td colspan="4">5</td></tr>
<tr><td>3.</td><td>Group</td><td>Rick Terrill</td><td>Luminant Power</td><td></td><td></td><td></td><td></td><td>X</td><td></td><td></td><td></td><td></td><td></td></tr>
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<tr><td colspan="3">1. Mike Laney</td><td></td><td colspan="6">ERCOT</td><td colspan="4">5</td></tr>
<tr><td colspan="3">2. David Youngblood</td><td></td><td colspan="6">ERCOT</td><td colspan="4">5</td></tr>
<tr><td colspan="3">3. Tommy Hardin</td><td></td><td colspan="6">ERCOT</td><td colspan="4">5</td></tr>
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4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick System Operator	NPCC	2
15.	Greg Mason	Dynegy Generation	NPCC	5
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
22.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10

5.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		RFC	5
2.	Mike Garton		NPCC	6

3.	Ron Broocks			SERC	1								
6.	Group	JT Wood	Southern Company Transmission	X									
	Additional Member		**Additional Organization**	**Region**	**Segment Selection**								
1.	Steve Bennett			SERC									
2.	Ben Pilleteri			SERC									
3.	William Shultz			SERC									
7.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates (PH)	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**	**Segment Selection**								
1.	Alvin Depew		Potomac Electric Power Co.	RFC	1								
2.	Evan Sage		Potomac Electric Power Co.	RFC	1								
3.	Carl Kinsley		Atlantic City Electric	RFC	1								
4.	Jason Parsick		Potomac Electric Power Co.	RFC	1								
5.	Rob Wharton		Delmarva Power & Light	RFC	1								
8.	Group	Carol Gerou	NERC Standards Review Subcommittee										X
	Additional Member		**Additional Organization**	**Region**	**Segment Selection**								
1.	Neal Balu		WPS Corporation	MRO	3, 4, 5, 6								
2.	Terry Bilke		Midwest ISO Inc.	MRO	2								
3.	Jodi Jenson		Western Area Power Administration	MRO	1, 6								
4.	Ken Goldsmith		Alliant Energy	MRO	4								
5.	Alice Murdock		Xcel Energy	MRO	1, 3, 5, 6								
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO	1, 3, 5, 6								
7.	Eric Ruskamp		Lincoln Electric System	MRO	1, 3, 5, 6								
8.	Joseph Knight		Great River Energy	MRO	1, 3, 5, 6								
9.	Joe DePoorter		Madison Gas & Electric	MRO	3, 4, 5, 6								
10.	Scott Nickels		Rochester Public Utilities	MRO	4								
11.	Terry Harbour		MidAmerican Energy Company	MRO	1, 3, 5, 6								
9.	Group	Bill Miller	Exelon			X		X					
	Additional Member		**Additional Organization**	**Region**	**Segment Selection**								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Thakur, Sudhir	Exelon Generation - Nuclear	RFC	5
2.	Spross, William J.	PECO	RFC	NA
3.	Catania, Vincent J.	PECO	RFC	
4.	Blazekovich, John J.	Exelon	RFC	NA
5.	Holderried, Jean M.	PECO	RFC	NA
6.	Belanger, David	Exelon Generation - Power	RFC	5

10.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender		WECC	1
2.	Francis Halpin		WECC	5
3.	Theodore Snodgrass		WECC	1

11.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ken Dresner	FirstEnergy	RFC	5
2.	Bill Duge	FirstEnergy	RFC	5
3.	Jim Detweiler	FirstEnergy	RFC	1
4.	Dave Folk	FirstEnergy		1, 3, 4, 5, 6
5.	Doug Hohlbaugh	FirstEnergy	RFC	1, 3, 4, 5, 6

12.	Individual	Ron Broocks	Virginia Electric and Power Company	X									
13.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
14.	Individual	Benjamin Church	NextEra Energy Resources					X					
15.	Individual	James A. Ziebarth	Y-W Electric Association, Inc.				X						
16.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
17.	Individual	Nicholas Klemm	Western Area Power Administration, Rocky Mountain Region (WACM)									X	
18.	Individual	Rao Somayajula	RelaibilityFirst Corporation										X

19.	Individual	Russ Schneider	Flathead Electric Co-op			X							
20.	Individual	Gene Henneberg	NV Energy	X		X		X					
21.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
22.	Individual	Catherine Koch	Puget Sound Energy	X									
23.	Individual	Michael Ayotte	ITC Holdings	X									
24.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
25.	Individual	Ed Davis	Entergy Services	X		X		X	X				
26.	Individual	James Starling	SCE&G	X		X		X	X				
27.	Individual	Jim Hubertus	PSEG	X		X		X	X				
28.	Individual	Saurabh Saksena	National Grid	X		X							
29.	Individual	Martin Bauer	US Bureau of Reclamation					X					
30.	Individual	Michael R. Lombardi	Northeast Utilities	X									
31.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
32.	Individual	Armin Klusman	CenterPoint Energy	X									
33.	Individual	Robert W. Cummings	NERC - Director of Event Analysis and Information Exchange										
34.	Individual	Nathan Lovett	Georgia Transmission Corporation	X									
35.	Individual	Jason Shaver	American Transmission Company	X									
36.	Individual	Adam Menendez	Portland General Electric Co.	X		X		X	X				

37.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

1. **The SDT determined that this standard is applicable to the following registered entities: Transmission Owners, Generator Owners and Distribution Providers according to the NERC Glossary of Terms that clearly defines these entities in all NERC Regional Reliability Organizations. Do you agree with this? If not, please explain in the comment area.**

Summary Consideration: Most commenters agreed with the registered entity applicabilities; however, several commenters questioned the inclusion of Distribution providers in the Applicability section. The drafting team revised the Applicability section of the draft standard to:

Distribution Providers that own transmission Protection Systems

Several commenters indicated that the Transmission Planner, Planning Coordinator, or the Transmission Operator should also be included in the Applicability section. While the drafting team recognizes that some of the information the respective owners may provide to other parties may be the result of work done by the Transmission Planner, Planning Coordinator, or the Transmission Operator, the drafting does not believe those entities should be included in the Applicability section and declined to make the change. Instead, the drafting team believes that the owners of the transmission Protection Systems are the entities responsible for meeting the requirements of PRC-001-2. According to the NERC Functional Model, it is the owners of the protection systems that are responsible for decisions related to those systems.

Organization	Yes or No	Question 1 Comment
Portland General Electric Co.		The standard as it is written does not address the way that PGE is organized. PGE has one Substation Engineering group that provides Protection System services to the generation and transmission functions that PGE is registered for. PGE does not have separate protection engineers within each of those functions. Therefore, it is not clear how some of the requirements of this standard apply to the way that PGE is organized.
Response: The drafting team recognizes that some entities are registered as both a Transmission Owner and as a Generator Owner. That dual registration may be supported by different engineering staffs or by the same group of engineers. The drafting team believes that the requirements in PRC-001-2 apply equally to both generator owners and transmission owners regardless of the umbrella of ownership or organizational structure. Even if the same engineer works on the Protection Systems on each side of the interconnection there must be documentation showing that the coordination issues have been addressed in the time frames detailed in the standard.		
Northeast Power Coordinating Council	Disagree	As it applies here and in other PRC standards, the determining factors for when a Distribution Provider “owns” a transmission Protection System is unclear. There should be a test, or a series of tests that a DP can perform to know whether or not it owns a transmission Protection System. There are a number of DPs who

Organization	Yes or No	Question 1 Comment
		own the equipment as defined in the Protection System definition, but owning the equipment alone does not justify the "own a transmission Protection System" identifier. Owning the equipment with certain operating requirements or criteria is when a DP is "owning a transmission Protection System". It should be made clear what the operating requirements or criteria are.
Response: The drafting team believes that the owner of transmission Protection Systems is the entity responsible for meeting the requirements of PRC-001-2. The term transmission Protection System is applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and initiating action to clear the protected element from all local sources. As such, these Protection Systems can be owned by Transmission Owners, Generation Owners, or in some cases Distribution Providers. For instance, in the event that the distribution transformer low side is connected to a potential source (generator or networked low side system) and there are Protection Systems installed to detect and initiate actions for transmission system faults, then these Protection Systems would be considered transmission Protection Systems, regardless of ownership.		
PSEG	Disagree	1. For PSE&G, portions of the processes described in the attachments are handled in a centralized PJM working group. The PJM Relay Subcommittee was developed to handle much of this coordination work. In this case, the Transmission Operator should be included in the Applicability List to ensure that the TO's are working together to develop, manage and maintain a coordinated process among the TO's. 2. Additionally, the TOP/RTO should develop a Generator Protection Subcommittee to support this process.
Response: The drafting team appreciates your comments. The Transmission Operator (TOP) is responsible for the real-time operating reliability of transmission assets which includes coordinating a number of operating function activities such as outage schedules; however, these tasks are being moved to other standards that pertain to the operator function. Coordinating relay settings and Protection System designs is clearly an engineering activity performed in the Planning Horizon. The drafting team believes that according to the NERC Functional Model the activities outlined in this draft standard are the responsibility of the Transmission Owner (TO), Generator Owner (GO) and the Distribution Provider. Even if the TOP acts as the coordinator between owners, the TOs and GOs are responsible for ensuring that these engineering activities are executed.		
Pepco Holdings, Inc - Affiliates (PH)	Disagree	In addition to the above identified entities the Planning Coordinator should be added. It is the Planning Coordinator that is responsible for conducting system dynamic studies (i.e., voltage and angular stability studies, system under frequency studies, etc.) and therefore the Planning Coordinator, not the Transmission Owner, should be responsible for providing the results of these studies to both the Transmission Owner and Generation Owner upon request (Ref. PRC-001-Attachments 2 & 3, Step1)
Response: The drafting team has written Requirement R4 to support the TPL standards, which define which entities are required to conduct dynamic studies. PRC-001 requires the Transmission Owner (TO) to provide the information to perform these studies. The expectation is that the TO would provide the results of any applicable studies it may possess, if requested. The dynamic study results may be used to justify certain design and setting		

Organization	Yes or No	Question 1 Comment
criteria.		
Flathead Electric Co-op	Disagree	It is unclear why Distribution Providers were included. Nothing in the standard development record seems to provide reliability justification for the inclusion. While coordination is an important component of reliability. Existing standards mandate sufficient coordination to maintain reliability at the LSE/DP level.
Response: The drafting team believes that the owner of transmission Protection Systems is the entity responsible for meeting the requirements of PRC-001-2. The term transmission Protection System is applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and initiating action to clear the protected element from all local sources. As such, these Protection Systems can be owned by Transmission Owners, Generation Owners, or in some cases Distribution Providers. For instance, in the event that the distribution transformer low side is connected to a potential source (generator or networked low side system) and there are Protection Systems installed to detect and initiate actions for transmission system faults, then these Protection Systems would be considered transmission Protection Systems, regardless of ownership.		
PNGC- Cowlitz PUD - Central Lincoln PUD group	Disagree	It is unclear why Distribution Providers were included. The SAR provides no reason, but references 693 and the SPCTF Report. Nothing in the 693 order supports the inclusion, and the SPCTF simply says they “assert” the inclusion without providing any reasoning. While coordination is desirable, the comment group is unconvinced that miscoordinations involving DPs rise to the level of being reliability issues as defined by the FPA.
Response: The drafting team believes that the owner of transmission Protection Systems is the entity responsible for meeting the requirements of PRC-001-2. The term transmission Protection System is applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and initiating action to clear the protected element from all local sources. As such, these Protection Systems can be owned by Transmission Owners, Generation Owners, or in some cases Distribution Providers. For instance, in the event that the distribution transformer low side is connected to a potential source (generator or networked low side system) and there are Protection Systems installed to detect and initiate actions for transmission system faults, then these Protection Systems would be considered transmission Protection Systems, regardless of ownership.		
Duke Energy	Disagree	The Standard Drafting Team should consider including the Transmission Planner and Planning Coordinators as applicable entities. There should be an additional requirement similar to R5 regarding information exchanges for planning studies. This should be a two-way information exchange that is iterative in nature. The system protection design features must be properly modeled and evaluated to ensure satisfactory system operation (i.e. stability) will be attained. The modeling and evaluation may show that changes are required of the original design. Also add the Transmission Planner and Planning Coordinator to the Attachments.
Response: The drafting team has written Requirement R4 to support the TPL standards, which define which entities are required to conduct planning studies. PRC-001 requires the Transmission Owner (TO), Generator Owner and Distribution Provider to provide the information to perform these		

Organization	Yes or No	Question 1 Comment
studies.		
Y-W Electric Association, Inc.	Disagree	Under Applicability, 4.1.3 "Distribution Providers that own transmission Protection Systems" is vague and subject to random and widely-varying interpretations because the term "transmission Protection System" is not defined. This lack of clarity is currently confounding compliance with PRC-004-1 and PRC-005-1 because entities do not know who the standard applies to. Writing the same undefined and unclear term into a new standard would gain nothing more than additional confusion in the industry. Otherwise, the applicability makes sense.
Response: The term transmission Protection System is applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and initiating action to clear the protected element from all local sources. As such, these Protection Systems can be owned by Transmission Owners, Generation Owners, or in some cases Distribution Providers. For instance, in the event that the distribution transformer low side is connected to a potential source (generator or networked low side system) and there are Protection Systems installed to detect and initiate actions for transmission system faults, then these Protection Systems would be considered transmission Protection Systems, regardless of ownership.		
Georgia Transmission Corporation	Agree	There is some question about whether or not this standard applies to generator owners which connect at sub transmission voltage levels. There is also question about whether or not the standard applies to protection for auxiliary systems.
Response: The drafting team appreciates your support. This standard applies to NERC registered Generator Owners connected at any voltage level. This standard also applies to the Protection System(s) affecting the interconnection between a generation facility and its associated transmission or distribution system and generally does not apply to auxiliary systems. The System Protection Coordination Supplementary Reference provides a list of protective devices that may require coordination with transmission or distribution system protective relays.		
Puget Sound Energy	Agree	Unclear what the applicability of Distribution Providers that interconnect with Generator Owners is intended to capture.
Response: The drafting team appreciates your support. In consideration of your comments and those of others, the Applicability section of the draft standard has been modified. The revised applicability for Distribution Providers now reads: Distribution Providers that own transmission Protection Systems		
American Transmission Company	Agree	ATC agrees but believe that the requirements should be broken out to only include one applicable entity per requirement. This format makes it easier to entities to understand their responsibilities.
Response: The drafting team appreciates your support. The drafting team considered this approach but believes that the requirements are written in a		

Organization	Yes or No	Question 1 Comment
concise manner.		
Luminant Power	Agree	Luminant thanks the SDT for their work on this standard and the opportunity to provide comments to this and the following questions.
Response: The drafting team appreciates your support.		
Western Area Power Administration, Rocky Mountain Region (WACM)	Agree	Need to include "as applies to the Bulk Electric Power System" for consistency with existing standards
Response: The standard draft team considered the use of the Bulk Electric System (BES) in the standard but the BES is not uniformly defined by the Regional Entities. The use of the registered entities: Transmission Owners, Generator Owners and Distribution Providers that own transmission Protection Systems was considered the appropriate solution since these terms are universally accepted NERC defined terms and include the entities that are responsible for maintaining a reliable electric system.		
Bonneville Power Administration	Agree	
E.ON U.S.	Agree	
Electric Market Policy	Agree	
Entergy Services	Agree	
Exelon	Agree	
FirstEnergy	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
NERC - Director of Event Analysis and Information	Agree	

Organization	Yes or No	Question 1 Comment
Exchange		
NERC Standards Review Subcommittee	Agree	
NextEra Energy Resources	Agree	
Northeast Utilities	Agree	
NV Energy	Agree	
Oncor Electric Delivery	Agree	
RelaibilityFirst Corporation	Agree	
SCE&G	Agree	
Southern Company Transmission	Agree	
System Protection	Agree	
US Bureau of Reclamation	Agree	
Virginia Electric and Power Company	Agree	
Wisconsin Electric	Agree	
Xcel Energy	Agree	
ITC Holdings	Agree	none

2. Due to the many meanings of coordination and our intention to clarify the purpose of the standard, the SDT has included a definition for the term "System Protection Coordination" as it applies to this standard. The intention was to target coordination of fault clearing protection systems. Do you agree that the definition is appropriate for this standard? If not, please explain in the comment area.

Summary Consideration: The majority of responders agreed with the definition as posted; however, several commenters disagreed with referencing the TPL Standards in the definition. The drafting team modified the definition to specifically reference "Table 1 – Steady State & Stability Performance Planning Events" of the NERC TPL Reliability Standards rather than trying to duplicate and enumerate the faults and contingencies that are detailed in the Table. The revised definition is shown below:

System Protection Coordination – the design and setting of Protection Systems so that the minimum number of power system elements will be removed from service when clearing faults while meeting the performance requirements specified within Table 1 – Steady State & Stability Performance Planning Events of the NERC Transmission Planning (TPL) reliability standards.

Other commenters stated that in their opinion coordination in this Standard should include other system conditions such as voltage and frequency excursions. The drafting team noted that these conditions are addressed by other existing standards or other standards currently under development.

Organization	Yes or No	Question 2 Comment
Portland General Electric Co.		The standard needs to define the following terms: (1) "All protective elements that result in a transfer trip" as that phrase is used in Attachment 1 (2) "Scheme" in the phrase "Scheme type" as used in the Attachments. Does a "scheme" refer only to communications-assisted tripping, or to a specific collection of protection elements?
Response: 1.The drafting team does not find that phrase in Attachment 1 regarding "transfer trip", but does find a phrase similar to that referencing a "generator trip." The drafting team believes the phrase used is clear without a separate definition. 2. Scheme type includes communication-aided and non-communication-aided systems as indicated in the "PRC-001-2 System Protection Coordination Supplementary Reference" document.		
Wisconsin Electric	Disagree	1. System Protection Coordination is independent of the NERC TPL standards, and there is no reason to reference them in the definition. 2. System Protection Coordination is affected by devices which operate for abnormal operating conditions,

Organization	Yes or No	Question 2 Comment
		not just fault clearing. 3. We propose an alternate definition: "System Protection Coordination - the design and setting of those Protection Systems affecting the reliability of the BES so that they remove the minimum number of power system elements from service."
Response: 1. The drafting team references the TPL standards rather than trying to duplicate and enumerate the faults and contingencies that are detailed in "Table 1 – Steady State & Stability Performance Planning Events" in the TPL standards. The concern about this reference leading to a continually changing definition as TPL standards change will be mitigated by changing the definition to reference the Table specifically. **2. The drafting team acknowledges that System Protection performance is affected by conditions other than faults but those conditions such as off nominal frequency and voltage are being addressed in other standards.** **3. Thank you for your proposed definition but the drafting team believes that your proposed definition would change the intended purpose of the standard. However, the drafting team has modified the initial definition of System Protection Coordination.**		
American Transmission Company	Disagree	ATC does not agree with the proposed definition. The definition should be limited to what is System Protection Coordination. Because approved Reliability Standards are part of an entities compliance obligation we do not feel that the reference to the TPL reliability standards is either necessary or appropriate. Suggested definition: System Protection Coordination: the design and setting of Protection Systems.
Response: The drafting team references the TPL standards rather than trying to duplicate and enumerate the faults and contingencies that are detailed in "Table 1 – Steady State & Stability Performance Planning Events" in the TPL standards. **Thank you for your proposed definition but the drafting team believes that your proposed definition would change the intended purpose of the standard. However, the drafting team has modified the initial definition of System Protection Coordination.**		
CenterPoint Energy	Disagree	1. CenterPoint Energy does not see a need to define such a long standing industry term, nor do we see a need to develop a reliability standard for relay coordination (please refer to response to Question 10). 2. However, if most entities agree with developing a standard that would serve as an umbrella over other standards and believe a definition is needed, the reference to NERC Transmission Planning (TPL) requirements should be deleted. Referring to TPL standards would result in an open-ended definition that would change whenever TPL requirements are revised.
Response: The drafting team is unaware of any universally approved definition. The drafting team references the TPL standards rather than trying to duplicate and enumerate the faults and contingencies that are detailed in "Table 1 – Steady State & Stability Performance Planning Events" in the TPL standards. The concern about this reference leading to a continually changing definition as TPL standards change will be mitigated by changing the		

Organization	Yes or No	Question 2 Comment
definition to reference the Table specifically.		
System Protection	Disagree	1) Replace "faults" with "electrical short-circuits" to clarify the definition. NERC Glossary defines Fault as "An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection." Broken wires and loose connections are very rare compared to short circuits. System Protection Coordination is done for short circuits, not for broken wires or loose connections. 2) We generally agree with creating this System Protection Coordination definition, if item 1 is addressed. 3) Attachments 1, 2, and 3 are inconsistent in that they use "Protection System Coordination" in their items 2, 5, and 6.
Response: 1) The drafting team maintains that the term "Fault" as defined in the NERC Glossary of Terms is appropriately used in the "System Protection Coordination" definition. Relay coordination studies are performed by applying short-circuits to the electrical system and comparing the operating times of up-stream and down-stream relays. If the up-stream relay operates in a time greater than the down-stream relay plus a safety margin, then coordination is achieved. In some instances coordination studies are required for conditions other than short-circuits. **2) Please see the answer to "1" above.** **3) Thank you very much for your observation. The Standard has been changed based on your comment. In the revised standard, Attachments 1, 2, and 3 each use the term, "System Protection Coordination" in steps 2, 5, and 6.**		
NERC - Director of Event Analysis and Information Exchange	Disagree	Fault clearing is only one aspect of protection coordination that must be done. Items such as over-voltage, under-voltage, frequency protection, loadability, etc., have been causal or contributory in a number of disturbances, including the August 14, 2003 Blackout. During that event, it is known that: 35 units tripped on undervoltage, 26 units tripped on overvoltage, and 59 units tripped on over/underfrequency. Clearly, those protective functions cannot be ignored in coordination. Similarly, during the September 18, 2007 MRO system separation, lack of coordination of seven generators with the regional over-frequency requirements caused the separation of Saskatchewan from Manitoba, resulting in the loss of over 900 MW of load. The System Protection and Control Subcommittee (SPCS) defined coordination in their NERC Technical Reference on Power Plant and Transmission System Protection Coordination as: Coordination of generation and transmission protection systems (for events external to the plant), means that power plant protection and related control elements must be set and configured to prevent unnecessarily tripping the generator prior to any transmission protection and related control systems acting first, unless the generator is in jeopardy by exceeding its design limits due to operating conditions, generator system faults, or other adverse potentially damaging conditions.
Response: The drafting team agrees that fault clearing is only one aspect of protection coordination. However, this is the only aspect of protection		

Organization	Yes or No	Question 2 Comment
coordination that is addressed by this standard. Other items such as over/under frequency, over/under voltage and relay loadability are already addressed by existing standards or are being addressed by new standards (PRC-006, PRC-010, PRC-023 and PRC-024). The drafting team believes that including those aspects of protection coordination would cause duplication or conflict of requirements and compliance measurements.		
NV Energy	Disagree	I agree that a clear definition of System Protection Coordination is useful, but suggest a few minor wording changes included in brackets [ ] to clarify: System Protection Coordination - the design and setting of Protection Systems so that [delete "they remove"] the minimum number of power system elements [add "will be removed"] from service when clearing faults while meeting the performance requirements specified within the NERC Transmission Planning (TPL) reliability standards.
Response: The drafting team thanks you for your comment and has modified the definition and adopted your proposed deletion and addition – and made other revisions based on comments from other stakeholders. The revised definition is shown below: **System Protection Coordination** – the design and setting of Protection Systems so that the minimum number of power system elements will be removed from service when clearing faults while meeting the performance requirements specified within Table 1 – Steady State & Stability Performance Planning Events of the NERC Transmission Planning (TPL) reliability standards.		
Pepco Holdings, Inc - Affiliates (PH)	Disagree	1. If the intent of the standard is to only target coordination of fault clearing protection systems, then the definition is adequate. However, the Supplementary Reference document identifies several voltage and frequency protective devices (24, 27, 50/27, 59, 81) which may require coordination. These are not “fault clearing protection systems”. Either they should be removed from the supplemental reference, or the definition of “System Protection Coordination” expanded to include what is intended with regard to “coordination” of these voltage and frequency devices. However, since Draft Standard PRC-024-1 is dedicated to the setting of generator voltage and frequency responsive relays to ride through transmission system faults and disturbances, it would seem appropriate to leave the “coordination” of voltage and frequency responsive protection systems in PRC-024-1 rather than address it in this standard. 2. Also, conformance to a “Regional Reliability Organization’s” off-nominal frequency plan, or to a Transmission Operator’s off-nominal voltage interconnection requirements, should not be part of this standard, as they are covered by other regional standards (i.e., PRC-006-RFC-01...) and agreements. 3. In addition, the Supplementary Reference document lists auto-reclosing (79) elements, including synchrocheck (25) elements and dead line supervision (27) elements, as protection devices that may require coordination. Auto-reclosing devices are by definition not part of a “Protective System” and are not included in the “Protective System Coordination” definition identified in this standard. As such, these elements should

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>also be removed from the Supplementary Reference.</td></tr>
<tr><td colspan="3">Response: 1. The drafting team agrees and has removed the references to voltage and frequency protective devices from the second draft of the supplemental reference for this document. Note the 50/27 is an Inadvertent Energization function and does need to be coordinated with transmission protection, and therefore was not removed.
2. The drafting team agrees and has removed references to the Regional Reliability Organization's off-nominal frequency plan from Step 1 of Attachments 2 and 3 in the revised standard.
3. The drafting team agrees that reclosing is not part of the Protection System definition; however, the reclosing scheme is a design and setting issue needed to be included in this exchange of information.</td></tr>
<tr><td>Southern Company Transmission</td><td>Disagree</td><td>It is suggested that the coordination should include overloads in addition to faults.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment but relay loadability is being covered in PRC-023.</td></tr>
<tr><td>Luminant Power</td><td>Disagree</td><td>Luminant suggests a slight modification to the definition as follows:
"System Protection Coordination - The design and setting of Protective Systems so that they perform with optimum reliability and selectivity while meeting the performance requirements specified within the NERC Transmission Planning (TPL) reliability standards."</td></tr>
<tr><td colspan="3">Response: Thank you for your proposed definition but the drafting team believes that your proposed definition would change the intended purpose of the standard. However, the drafting team has modified the initial definition of System Protection Coordination. The revised definition is shown below:
System Protection Coordination – the design and setting of Protection Systems so that the minimum number of power system elements will be removed from service when clearing faults while meeting the performance requirements specified within Table 1 – Steady State & Stability Performance Planning Events of the NERC Transmission Planning (TPL) reliability standards.</td></tr>
<tr><td>Duke Energy</td><td>Disagree</td><td>Performance requirements are not just in the TPL standards. Revise definition to read as follows:
"System Protection Coordination - the design and setting of Protection Systems so that they remove the minimum number of power system elements from service when clearing faults while meeting the performance expectations of the TP and PC.</td></tr>
<tr><td colspan="3">Response: Thank you for your proposed definition but the drafting team believes that your proposed definition would change the intended purpose of the standard. However, the drafting team has modified the initial definition of System Protection Coordination. The revised definition is shown below:
System Protection Coordination – the design and setting of Protection Systems so that the minimum number of power system elements will be</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
removed from service when clearing faults while meeting the performance requirements specified within Table 1 – Steady State & Stability Performance Planning Events of the NERC Transmission Planning (TPL) reliability standards.		
PNGC- Cowlitz PUD - Central Lincoln PUD group	Disagree	The comment group does not agree with the definition, since it relies on TPL standards that are currently under revision. Subject entities must track the effective dates of multiple standards and time their compliance accordingly. Also, the definition fails to identify which TPL standards are included in the definition. It also creates confusion regarding applicability, since some entities are being directed to standards that are not applicable to them. The comment group would prefer a standalone definition.
Response: The drafting team references the TPL standards rather than trying to duplicate and enumerate the faults and contingencies that are detailed in "Table 1 – Steady State & Stability Performance Planning Events" in the TPL standards. The concern about which standard is applicable is mitigated by changing the definition to reference the Table specifically. Although the TPL standards are not applicable to all entities, Table 1 lists the faults and contingencies used to evaluate System Protection Coordination.		
E.ON U.S.	Disagree	The definition may be appropriate; however, it needs to be clearly included with the standards itself. Currently, that definition is outside of the document.
Response: The drafting team used the format specified by NERC.		
Xcel Energy	Disagree	The definition needs further clarification. Does the definition intend that coordination be achieved under extreme conditions, such as removal of all "in-feed" at remote buses (multiple contingencies), or is coordination under N-1 contingencies adequate?
Response: The definition has been modified to reference "Table 1 – Steady State & Stability Performance Planning Events" in the TPL standards. Table 1 lists the faults and contingencies used to evaluate System Protection Coordination.		
Exelon	Disagree	The definition should include any conditions that could cause any of the generator relay elements as shown in the PRC-001-2 reference document currently posted on the NERC website to trip a generator.
Response: The conditions defined in the NERC Technical Reference Document on "Power Plant and Transmission System Protection Coordination" encompasses other items such as over/under frequency, over/under voltage and relay loadability that are already addressed by existing standards or are being addressed by new standards (PRC-006, PRC-010, PRC-023 and PRC-024) as well as other items that do not require coordination. The drafting team believes that including those aspects of protection coordination that are covered in other standards would cause duplication or conflict of requirements and compliance measurements.		

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Subcommittee	Disagree	1. The MRO NSRS has a concern that by making this standard applicable to all Distribution Protection systems, regardless of their location or relationship to the BES. 2. The definition should be limited to what is System Protection Coordination. Because approved Reliability Standards are part of an entity's compliance obligation the MRO NSRS does not feel that the reference to the TPL reliability standards is necessary. Suggested definition: System Protection Coordination: the design and setting of Protection Systems that impact the reliability of the BES so that they remove the minimum number of power system elements from service.
Response: 1. The draft standard only applies to transmission Protection Systems owned by Distribution Providers. Note that the Applicability section has been modified in regards to the Distribution Provider and now says, "Distribution Providers that own transmission Protection Systems"- the phrase, "or that interconnect with Generators" has been removed from the revised standard. 2. The drafting team references the TPL standards rather than trying to duplicate and enumerate the faults and contingencies that are detailed in "Table 1 – Steady State & Stability Performance Planning Events" in the TPL standards. The definition has been modified to reference this table. Thank you for your proposed definition but the drafting team believes that your proposed definition would change the intended purpose of the standard.		
Flathead Electric Co-op	Disagree	The standard development process should not unnecessarily create new definitions; standard definitions should be globally developed for consistency with the NERC Glossary. System Protection is defined in the NERC Glossary and there are sufficient defined terms for purposes of this standard.
Response: It is within the purview of the drafting team to develop new definitions if the drafting team believes it is necessary to better clarify the meaning of a term. In this case, the word "coordination" has multiple meanings; therefore, the drafting team believes it necessary to focus on a specific interpretation of System Protection Coordination. "Coordinate" was often being used when "communicate" was the intended purpose.		
NextEra Energy Resources	Disagree	We do not disagree with the definition as written and suggest modifying the statement to end after "Fault."
Response: The phrase after "faults" was included in the definition to address system performance criteria.		
Puget Sound Energy	Agree	The standard should address coordination of the systems, but the excessive focus on timeframes relating to communications implies coordination of communication to be a greater intent.
Response: The drafting team appreciates your support. Timeframes were included to make the requirements measurable.		
FirstEnergy	Agree	Yes, the SDT did a good job of defining a very ambiguous term which has caused much confusion in interpreting the current PRC-001-1 standard.

Organization	Yes or No	Question 2 Comment
Response: The drafting team appreciates your support.		
ITC Holdings	Agree	1. The performance requirements specified within the NERC TPL reliability standards specify system performance for various contingencies. The contingencies include stuck breaker and protective relay system failure. We understand that if the # of elements removed and associated speed for these contingencies result in acceptable system performance the coordination is considered adequate. Is this in agreement with the definition? 2. Please provide a specific example or two where coordination meets the TPL reliability standards. Also please provide specific examples of where coordination does not meet the reliability standards. Also please provide an example of applying a test criterion to determine if the protection coordination is adequate.
Response: The drafting team appreciates your support. The drafting team does not agree that meeting acceptable system performance necessarily equates with adequate System Protection Coordination. An example where coordination meets TPL reliability standards is when a fault is cleared normally so that the minimum number of power system elements is removed from service and the system remains stable. If System Protection Coordination is achieved, the drafting team believes that performance requirements of Table 1 of the TPL standards will be met. However, the lack of System Protection Coordination can result in an overtrip which can cause a loss of load that will not meet the performance requirements. Test criteria would be based on the two parts of the definition of System Protection Coordination.		
Georgia Transmission Corporation	Agree	It isn't clear about which voltage level the standard applies to or if it just applies to the BES.
Response: The drafting team appreciates your support. The draft team considered the use of the Bulk Electric System (BES) in the standard but the BES is not uniformly defined by the Regional Entities. The use of the registered entities: Transmission Owners, Generator Owners and Distribution Providers that own transmission Protection Systems was considered the appropriate solution since these terms are universally accepted NERC defined terms and include the entities that are responsible for maintaining a reliable electric system. This standard applies to the applicable entities interconnected at any voltage level.		
RelaibilityFirst Corporation	Agree	Need to add “as applicable to Bulk Electric System” to make it consistent with other standards.
Response: The drafting team appreciates your support. The drafting team considered the use of the Bulk Electric System (BES) in the standard but the BES is not uniformly defined by the Regional Entities. The use of the registered entities: Transmission Owners, Generator Owners and Distribution Providers that own transmission Protection Systems was considered the appropriate solution since these terms are universally accepted NERC defined terms and include the entities that are responsible for maintaining a reliable electric system.		

Organization	Yes or No	Question 2 Comment
Western Area Power Administration, Rocky Mountain Region (WACM)	Agree	Not sure about consistency with automatic reclosing. Does TPL include automatic reclosing; if not should 79 relays be included in this standard?
Response: The drafting team appreciates your support. The drafting team agrees that reclosing is not part of the Protection System definition; however, the reclosing scheme is a design and setting issue needed to be included in this exchange of information and the proposed TPL-001-1 requires simulating automatic reclosing.		
Bonneville Power Administration	Agree	
Electric Market Policy	Agree	
Entergy Services	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Northeast Power Coordinating Council	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
PSEG	Agree	
SCE&G	Agree	
US Bureau of Reclamation	Agree	
Virginia Electric and Power Company	Agree	

Organization	Yes or No	Question 2 Comment
Y-W Electric Association, Inc.	Agree	

3. This draft standard has placed specific deadlines in the requirements for information exchange, review, agreement and implementation. Do you believe that the amount of time provided for each of these actions is acceptable? If not, please explain in the comment area which times should be changed and what would be more appropriate.

Summary Consideration: Most responders disagreed with the specificity of the time requirements; the comments revolved around three issues:

1) Time intervals should include 'or as agreed to by the parties'.
2) The references to 'month' should be changed to 'days.'
3) The 6 month time frame for initial notification may not be satisfactory in certain circumstances.

In response to issue (1), the drafting team included the phase 'or according to an agreed upon schedule' to the Standard. For issue (2), the drafting team changed the references to one and two months to thirty and sixty calendar days, but left the reference to 6 months unchanged. For issue (3), the drafting team modified the Attachments to add flexibility; the schedules can now be set through the mutual agreement of all entities.

Organization	Yes or No	Question 3 Comment
Wisconsin Electric	Disagree	1. The requirement in R2 to provide drawings and applied instrument transformer ratios six months prior to the In-Service date is neither practical nor achievable. This information may not be available until shortly before the equipment is installed due to required design or settings changes, construction problems, etc. The information required in R2 should be changed to Scheme Type, One Line Diagram, and Type of Relay and associated communications equipment only. The deadline should be changed to thirty calendar days prior to the In-Service Date. Also in R2, the Note relating to equipment replaced due to failures should only apply if the settings have been changed. 2. In R4, the entity is required to provide unlimited information in a one month timeframe. This requirement should be changed to limit the scope to provide only information on protection devices or elements required for System Protection Coordination as listed in the Supplementary Reference. Thirty calendar days is sufficient, with forty-five days allowed for requests for more than three facilities. 3. In R1, similar to above, the Settings and Schemes information required must be limited to the specific protection devices or elements listed in the Supplementary Reference. This will help the registered entities to focus their attention on those requests that truly affect reliability of the BES. Thirty calendar days is sufficient, with forty-five days allowed for requests for more than three facilities. 4. Using "months" for deadlines is vague and subject to a variety of interpretations. Rather, using calendar days is more precise.

Organization	Yes or No	Question 3 Comment
Response: 1. The drafting team believes that preliminary information, i.e. drawings, etc. is available six months in advance of the Protection System modification or installation. The drafting team agrees with your comment about the instrument transformers and has changed the wording in Attachments 1, 2, and 3 from “applied” to “proposed.” The drafting team has changed the applicable note related to “failures” in the Attachments 1, 2, and 3 to address your concern. **2. R4 has been changed to R5. The drafting team has modified the wording to suggest the type of information necessary to perform planning studies (such as functional description, purpose and limitations). Not all information included in the supplementary reference need be supplied to the Transmission Planner. The drafting team has changed the reference from one month to thirty calendar days, or a mutually agreed upon schedule.** **3. The drafting team has removed the specific examples of the information in R1. The drafting team has changed the reference from “one month” to “thirty calendar days, or a mutually agreed upon schedule...”** **4. The drafting team has changed any monthly reference to the appropriate number of calendar days.**		
Georgia Transmission Corporation	Disagree	Agreed upon timeframes between entities would better facilitate transfer of information.
Response: The drafting team has modified the Attachments and Standard regarding timeframes so that mutual agreements can be utilized in certain cases.		
Western Area Power Administration, Rocky Mountain Region (WACM)	Disagree	As applies to Attachments 1, 2 and 3 I feel that there should be flexibility in the deadlines. Under "Conditions" the six months should be worded "six months prior to the proposed in service date ... or by documented agreement by the affected parties." Similarly for Step 4 - "two months prior to the in-service date ... or by documented agreement by the affected parties."
Response: The drafting team has modified the Attachments regarding timeframes so that mutual agreements can be utilized in certain cases.		
ITC Holdings	Disagree	1. Where only one month deadline is indicated, there should be the statement “or agreed upon schedule”. 2. In attachments 1, 2 and 3 the 6 month requirement for notice is too short in many cases. We suggest 9 months to one year. 6 months is not enough time for budgeting and construction scheduling.
Response 1. The drafting team has changed the reference from “one month” to “thirty calendar days, or a mutually agreed upon schedule.” **2. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. If the 6 months is not enough time for budgeting or construction, then a longer time frame can be negotiated. The drafting team believes that Interconnection Agreements will dictate the minimum times required to request an interconnection.**		

Organization	Yes or No	Question 3 Comment
System Protection	Disagree	1) For projects that only need setting changes 6 months is sufficient notice. This will cause planners to have to give more advance notice for some projects than they do now. 2) For projects needing equipment changes one year is needed, given equipment, drafting, construction & commissioning lead times and time of year outage constraints. 3) The proposed deadlines are reasonably achievable most of the time. For R1, six months must be allowed due to sheer volume. 4) Of course, these deadlines create another burden to demonstrate compliance.
Response: **1. & 2. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. If the 6 months is not enough time for budgeting or construction, then a longer time frame can be negotiated. The drafting team believes that Interconnection Agreements will dictate the minimum times required to request an interconnection.** **3. The drafting team has changed the reference from "one month" to "thirty calendar days, or a mutually agreed upon schedule."** **4. The drafting team thanks you for your comment.**		
FirstEnergy	Disagree	In general, the standard is overly prescriptive and borders on procedural statements rather than reliability standard requirements; specifically the detailed steps included within the attachments to the standard. As stated, the deadlines in some cases may be too short and in other cases may be too long. For example: 1.It should be permissible to schedule a small change without a six months lead time as specified in the Attachments. 2. Requirements R1 and R4, and Parts 5.3 and 6.3, have the phrase "within one month of receipt of request". In some cases this may not be enough time and it should be acceptable for the entities involved to agree to a deadline appropriate for the situation. We suggest replacing the phrase "within one month of receipt of request" with the phrase "per an agreed upon schedule".
Response: **1. The drafting team believes that all the steps in the Attachments are needed. This will allow all entities adequate time to properly address Protection System Coordination issues. The standard has been modified to clearly state that the time frames in Attachments can change with the mutual agreement of all entities.** **2. The drafting team has changed the references in Requirements R1, R4, R5, and R6 of the standard from "one month" to "thirty calendar days, or a mutually agreed upon schedule."**		
Luminant Power	Disagree	1. Luminant believes the time frame in R1 is prohibitive if an entity asks for the settings immediately after the standard is approved. Luminant suggests that the SDT utilize the six month time frame in R6 (in R1) for the time period immediately after the standard is approved. After the initial six months has passed, the 30 day period upon request is acceptable.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>2. Also, if a request is made for the settings, and no change has occurred since the last transmittal, a response of “No changes” would be acceptable in lieu of a full re-submittal.

3. For new or revised Protection Systems, 3 months is a more appropriate time frame. A six month requirement would result in incomplete information and premature information being transmitted.</td></tr>
<tr><td colspan="3">Response: 1. The drafting team considered your comments as well as others when we modified the Implementation Plan.

2. If an entity is requesting settings then the settings should be sent per requirement R1 whether or not changes have occurred since the last request.

3. The drafting team believes that preliminary information, i.e. drawings, etc. is available six months in advance of the Protection System modification or installation. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities.</td></tr>
<tr><td>Duke Energy</td><td>Disagree</td><td>1. R1, R5.3 and R6.3 deadlines should be modified to "1 month or a mutually agreed upon schedule", since requests for information could be voluminous for a large system.

2. R4 should be on a mutually agreed upon schedule instead of 1 month, since requests could be voluminous, and the information is for planning studies, not operations.

3. Attachments 1, 2 and 3, steps 2 & 5, should be modified to "1 month or a mutually agreed upon schedule" instead of 1 month.

4. Attachment 2, step #6, delete the phrase “prior to the in-service date”, since implementation may have a different in-service date for the Generator, due to outage schedules and trip risk mitigation concerns. The basis for the change may be for infrequent alignments or multiple element outages contingencies and does not justify modifying the generation protection with the generation on-line.</td></tr>
<tr><td colspan="3">Response: 1. & 2. The drafting team has changed the references in Requirements R1, R4, R5, and R6 of the standard from “one month” to “thirty calendar days, or according to an agreed upon schedule.”

3. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities.

4. The drafting team has modified the Attachments to clarify that it is the in-service date of the Protection System.</td></tr>
<tr><td>Virginia Electric and Power Company</td><td>Disagree</td><td>1. One month time frames should be extended to 2 months, or agreed upon time frame by both entities. Basic business practice for turnaround times, assignment of work, etc. require additional time for non-emergency activities.

2. Six month time frames indicated in Attachments 1, 2, and 3 should be extended to 1 year, which is the typical time frame necessary to initiate and implement system configuration and protection changes for</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		non-emergencies. 3. Step 4 two month time frame should be extended to 6 months, which is the typical time frame to initiate and implement setting changes for non-emergencies.
Response: 1. The drafting team has changed the references in Requirements R1, R4, R5, and R6 of the standard from "one month" to "thirty calendar days, or according to an agreed upon schedule." **2. & 3. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities.**		
Portland General Electric Co.	Disagree	1. PGE believes the time period to respond to a request under Requirement 1 should be much less than one month. PGE suggests a time period of 2 weeks. One month is too long for a recognized coordination issue to go unresolved. 2. PGE believes that in certain cases it will not be possible for a registered entity to give notice six months in advance of a new or revised Protection System or a system configuration change, as is required in the attachments. In the case of a Transmission Owner's new transmission system, construction timelines are often so tight that it is not possible to develop the protection settings six months in advance. In other cases, a registered entity needs to make immediate configuration changes in response to new information. 3. The footnote that exempts "changes that are a reaction to failures of components in Protection Systems if the replacement of components is with functional equivalents" needs to be expanded to allow for such unilateral action in cases where reliability could be immediately approved. In addition, the standard should allow for shortening of the timelines by mutual agreement between the parties.
Response: 1.R1 is not intended to resolve known miscoordination issues. R1 is to ensure that current Protection System information is available to requesting entities within thirty calendar days. **2. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. Attachments 1, 2, and 3 do not require the settings to be developed six months in advance.** **3. The drafting team has modified the footnote to allow for expedited actions as a result of Misoperations but coordination between interconnecting entities is still required.**		
Y-W Electric Association, Inc.	Disagree	1. Providing months of advance notice to change the settings in a relay is not practical. If a problem is experienced in a protection system caused not by any equipment failure but by a poorly chosen setting, no entity is going to sit on two or more additional months of possible Misoperations while they coordinate with another entity. This would be counterproductive to the Congressionally-mandated goal of improving the reliability of the bulk power system by requiring entities to wait to correct known problems while

Organization	Yes or No	Question 3 Comment
		subjecting consumers to additional outages. 2. The other concern is that, by making the process to improve one's protective facilities so cumbersome, this standard has the real potential to discourage smaller entities from upgrading protection systems to newer and more modern equipment that could greatly improve the reliability of both the bulk electric system and the local distribution system.
Response: 1. The drafting team has modified the footnote in Attachments 1, 2, and 3 to allow for expedited actions as a result of Misoperations but coordination between interconnecting entities is still required. **2. The drafting team believes that all the steps in the Attachments are needed. This will allow all entities adequate time to properly address Protection System Coordination issues.**		
E.ON U.S.	Disagree	1. Six months may not be practical. For example, if there is a generator outage and a relay needs to be replaced during that outage, it is impractical to have the unit out for six months in order that the transmission provider has six months notice. Attachment 1 might be better stated: “At least six months prior or a mutually agreeable timetable to the proposed in-service date of any of the following.” 2. The footnote currently addresses reaction to failures only, but that does not address every situation that might be discovered during an outage.
Response: 1. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. **2. The drafting team has modified the footnote to allow for expedited actions as a result of Misoperations but coordination between interconnecting entities is still required.**		
PNGC- Cowlitz PUD - Central Lincoln PUD group	Disagree	1. The 6 month period from the attachments 1 - 3 should be allowed to be shortened with the approval of all the affected parties. 2. The one month turnaround on information requests will be difficult for smaller entities that have only one protection engineer, or contract the service.
Response: 1. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. **2. The drafting team believes that the thirty calendar day schedule is acceptable; however, the standard has been modified to allow mutually agreed upon schedule changes.**		
Northeast Utilities	Disagree	1. The one month deadline specified in Requirements R1, R4, and R5.3, may not be acceptable given the potential scope of the request for information. A more appropriate time requirement would be “per the

Organization	Yes or No	Question 3 Comment
		mutually agreed upon schedule or within one month of receipt of request". 2. The six month deadline specified in Requirements R.5.1 is not realistic given the scope of work that will be required to fulfill this requirement (particularly since some applications may have unique features that will require non-standard descriptions, and the exceptions would need to be located before the descriptions could be developed). To gather the general description, purpose and limitations of each existing type of transmission protection scheme applied on the system will require a long term dedicated effort that may take more than a year to complete. A time frame of 2 years would be a more realistic requirement. 3. Additionally, it should be required that the Transmission Operator perform an assessment to determine the adequacy of protection scheme information provided by the Transmission Owner and Distribution Provider to date, and inform the Transmission Owner and Distribution Provider of any additional information required.
Response: 1. The drafting team has changed the references in Requirements R1, R4, R5, and R6 of the standard from "one month" to "thirty calendar days, or according to an agreed upon schedule." **2. The drafting team believes that six months is sufficient.** **3. The drafting team disagrees. The drafting team believes this is outside the scope of this standard.**		
Southern Company Transmission	Disagree	The one month time frame could be too short depending on how much information is requested. (agree with Southern_Comment_Form...)
Response: The drafting team believes that the thirty calendar day schedule is acceptable; however, the standard has been modified to allow mutually agreed upon schedule changes.		
Flathead Electric Co-op	Disagree	The one month turnaround on information requests will be difficult for smaller entities that have only one protection engineer, or contract the service.
Response: The drafting team believes that the thirty calendar day schedule is acceptable; however, the standard has been modified to allow mutually agreed upon schedule changes.		
Exelon	Disagree	1. The party should have the capability of negotiating the appropriate timeline based on the scope of the project and not be subject to the 6 month timeframe. 2. The dispute resolution process should resolve any negotiated timelines not agreed on by the parties.

Organization	Yes or No	Question 3 Comment
		3. If a protective device is bypassed and adequate backup exists with the device, the timeline should not apply.
Response: 1. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. **2. The drafting team agrees.** **3. Real time operating decisions are outside the scope of this standard. However, permanently bypassing existing protection is a Protection System design change and requires a review that is addressed in R2 and R3 of the draft standard.**		
Pepco Holdings, Inc - Affiliates (PH)	Disagree	The problem with specifying deadlines is that each project is unique in scope. For major new interconnections with a large number of protective systems which could be affected, the time frames listed for review may be too short. On the other hand, for smaller projects, or those involving minor changes to existing protective systems, the time frames may be excessive. For instance, the requirement for submittal of device settings at least two months prior to the project in-service date may in many cases be impractical. Some settings (e.g., coordinating delay timers on directional comparison blocking schemes) are re-set or "tweaked" during final end-to-end commission testing to ensure adequate margins. These final setting adjustments are made and agreed upon during testing that takes place during facility outages immediately before the final cut-in of the protective system. The intent of this standard is to ensure that Protective System designs and settings are communicated between and accepted by interconnecting entities to ensure the Protective Systems are coordinated and function in an integrated manner. Establishing arbitrary time frames for this process to unfold creates unnecessary scheduling and resource problems, and does not add value to the intent of the Standard. Providing a requirement that the entities should establish and agree on the scope and schedule (including data exchange and review) when implementing new or proposed revisions, and to document such agreement, would seem to be a sufficient auditable measure of compliance without prescriptive timelines.
Response: The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. If the six months is not enough time for budgeting or construction, then a longer time frame can be negotiated. The drafting team believes that Interconnection Agreements will dictate the minimum times required to request an interconnection. The drafting team believes that all the steps in the Attachments are needed. This will allow all entities adequate time to properly address Protection System Coordination issues.		
NextEra Energy Resources	Disagree	1. The six month lead time on in-service dates is problematic. The timelines mentioned in the standard do not in any way improve reliability which is the primary purpose of any reliability standard. Also, if there are "business agreements/contractual agreements" between Generator Owner & Transmission Owner that provides timelines for the project, they should be the governing documents for those timelines. Creating new deadlines as in this standard might likely contradict standing business agreements/contractual agreements and will be confusing. Also, these timelines will be difficult to track and will require logging

Organization	Yes or No	Question 3 Comment
		and maintenance of every phone call, email, document, etc to comply with the standard. 2. This level of record keeping is cumbersome and expensive and by itself does not enhance reliability. 3. Additionally, the timeline is unclear as to what actions are applicable to the timeframe.
Response: **1. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. If the six months is not enough time for budgeting or construction, then a longer time frame can be negotiated. The revised standard does not preclude the need to follow other established requirements, tariffs, contracts or agreements. The drafting team believes that all the steps in the Attachments are needed. This will allow all entities adequate time to properly address Protection System Coordination issues.** **2. The drafting team thanks you for your comment and believes recordkeeping is necessary.** **3. The drafting team thanks you for your comment and has modified the Attachments.**		
National Grid	Disagree	1. The timelines mentioned in the standard do not in any way improve reliability which is the primary purpose of any reliability standard. 2. Also, if there are “business agreements/contractual agreements” between parties involved that provide timelines for the project, they should be the governing documents for those timelines. Creating new deadlines as in this standard might likely contradict standing business agreements/contractual agreements and will be confusing. 3. Also, these timelines will be difficult to track and will require logging and maintenance of every phone call, email, document, etc to comply with the standard. This level of record keeping is cumbersome and expensive and by itself does not enhance reliability.
Response: 1. The drafting team thanks you for your comment. The intent of providing timelines is to facilitate cooperation between entities. Without a ‘due date’ there may be instances where one entity doesn’t provide needed data to another entity within a reasonable time period. **2. The revised standard does not preclude the need to follow other established requirements, tariffs, contracts or agreements.** **3. The drafting team believes that all the steps in the Attachments are needed. This will allow all entities adequate time to properly address Protection System Coordination issues.**		
Northeast Power Coordinating Council	Disagree	1. The timelines mentioned in the standard do not in any way improve reliability which is the primary purpose of any reliability standard. 2. Also, if there are “business agreements/contractual agreements” between parties involved that provide timelines for the project, they should be the governing documents for those timelines. Creating new deadlines as in this standard might likely contradict standing business agreements/contractual

Organization	Yes or No	Question 3 Comment
		agreements and will be confusing. 3. Also, these timelines will be difficult to track and will require logging and maintenance of every phone call, email, document, etc to comply with the standard. This level of record keeping is cumbersome and expensive and by itself does not enhance reliability. Alternatively a very liberal flexibility governing deadlines where they must be specified could be considered, but it would be difficult in this standard to address and cover all the situations that might arise, or times agreed to by all parties.
Response: 1. The drafting team thanks you for your comment. The intent of providing timelines is to facilitate cooperation between entities. Without a 'due date' there may be instances where one entity doesn't provide needed data to another entity within a reasonable time period. **2. The revised standard does not preclude the need to follow other established requirements, tariffs, contracts or agreements.** **3. The drafting team believes that all the steps in the Attachments are needed. This will allow all entities adequate time to properly address Protection System Coordination issues.**		
Entergy Services	Disagree	1. There needs to be provisions for emergency projects (other than component failures) that may need to be in service in less than the 6 month notification timeframe. 2. Also, the applied CT ratio is typically not determined until settings are completed and would need to be transmitted with the settings 2 months prior to the in-service date.
Response: 1. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. **2. The drafting team agrees with your comment about the instrument transformers and has changed the wording in Attachments 1, 2, and 3 from "applied" to "proposed."**		
MRO NERC Standards Review Subcommittee	Disagree	1. These time frames are unacceptable and perhaps unachievable under ideal circumstances. The deadlines listed for new or revised protection schemes are not practical. Large, interconnection projects typically require segmenting the work and close coordination of engineering. Drawings, for instance, may be needed for multiple segments, and to require a six month lead time to provide a drawing would be unrealistic. The MRO NSRS believes the detailed procedures defined in Attachment#1 should be deleted because they are too prescriptive for a standard. A standard should say "what" instead of "how" as currently being reviewed by a NERC standards development initiative chaired by Gerry Cauley; he recently gave a presentation titled "Developing Results-Based Standards" to the NERC Standards Committee (on 10/07/2009). If however, an Attachment #1 is retained the lead times as described should be reduced to three months and, more importantly, the list of information modified. Scheme type and types of relays/communication equipment should be known well in advance along with an established one-line diagram. Drawings (other than the one-line) may not be completed and should be removed from

Organization	Yes or No	Question 3 Comment
		the list. Instrument transformer ratios may not be finalized until relay settings are done, which may be only one to two months in advance; therefore, this bullet item should be removed. Several of the additional information items may also be unavailable until closer to in-service, such as transformer tap positions and factory test results that would provide actual impedance values. It would then follow that the times listed in Attachment 1 under steps 2, 3 and 4 should be modified. Leaving the times to an agreed upon schedule is a more practical solution. 2. Under R3 and Attachments 2 and 3, the lead times should be modified as described above for R2. For R4, there should be a limited scope to comply in one month. An entity should not be required to provide everything, everywhere in 30 days or less. 3. R5 should be deleted. This is undue documentation that does not improve system reliability. The industry already coordinates on a regular basis. Protection engineers who already understand the description, purpose, and limitation of relaying already exchange information on a regular basis to ensure coordination. Data exchange and requirements should be limited to registered entities only. An entity could be overwhelmed with requests from just anyone. Only those entities that are subject to the same standards and penalties should be allowed to request data. Otherwise there is the potential for disproportional burden where one entity is subject to non-compliance and the requestor is not.
Response: **1. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. The drafting team believes that preliminary information, i.e. drawings, etc. is available six months in advance of the Protection System modification or installation.** **2. Requirement R4 only includes information necessary to perform planning studies. The drafting team has changed the reference from one month to thirty calendar days, or a mutually agreed upon schedule, in support of your suggestion. The drafting team agrees with your comment about the instrument transformers and has changed the wording in Attachments 1, 2, and 3 from "applied" to "proposed".** **3. This information is required to support real-time operations. The Transmission Operator referenced in this standard is a functional entity that has registered for compliance and is subject to penalties for noncompliance with NERC's reliability standards.**		
American Transmission Company	Disagree	1. Under ideal circumstances, the times are acceptable; however, deadlines listed for new or revised protection schemes are not practical. Large, interconnection projects typically require segmenting the work and close coordination of engineering. Drawings, for instance, may be needed for multiple segments, and to require a six month lead time to provide drawing would be problematic. Specifically, under R1, the 30 day requirement for requested information is acceptable. 2. Under R2, Att. 1, the lead times as described should be reduced to three months and, more importantly, the list of information modified. Scheme type and types of relays/communication equipment should be known well in advance along with an established one-line diagram. Drawings (other than the one-line)

Organization	Yes or No	Question 3 Comment
		may not be completed and should be removed from the list. Instrument transformer ratios may not be finalized until relay settings are done, which may be only one to two months in advance; therefore, this bullet item should be removed. Several of the additional information items may also be unavailable until closer to in-service, such as transformer tap positions and factory test results that would provide actual impedance values. It would then follow that the times listed in Att. 1 under steps 2, 3 and 4 should be modified. Leaving the times to an agreed upon schedule is a more practical solution. 3. Under R3 and Attachments 2 and 3, the lead times should be modified as described above for R2. R4, R5 and R6 times are acceptable as listed.
Response 1, 2, & 3. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. The drafting team believes that preliminary information, i.e. drawings, etc. is available six months in advance of the Protection System modification or installation. The drafting team agrees with your comment about the instrument transformers and has changed the wording in Attachments 1, 2, and 3 from "applied" to "proposed."		
Puget Sound Energy	Disagree	1. Work that impacts protection systems is often scheduled around outage availability, funding, and permit constraints. The overarching "Conditions" of the Attachments to begin a process at least six months prior to the proposed in service date may be well intended, but allows for no flexibility if things can or should be implemented quicker. 2. The specifications in the Attachments of timeframes for response between requests appear to allow for shorter timeframes which should allow for an overall shorter process if agreed. The timeframe requirements will make scheduling outages even more complex than they are already. The inclusion of the timeframes also requires significant tracking to demonstrate compliance within these time frames. When communication between two of the identified functions happen to be within the same organization or the same person, it becomes an unnecessary documentation exercise.
Response: 1. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. **2. The drafting team believes that all the steps in the Attachments are needed. This will allow all entities adequate time to properly address Protection System Coordination issues.**		
RelaibilityFirst Corporation	Agree	MOD standards have a 30 day deadlines, suggest changing the deadline from one month to 30 days to be consistent.
Response: The drafting team has changed any monthly reference to the appropriate number of calendar days.		

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Agree	
Electric Market Policy	Agree	
Manitoba Hydro	Agree	
NV Energy	Agree	
Oncor Electric Delivery	Agree	
PSEG	Agree	
SCE&G	Agree	
US Bureau of Reclamation	Agree	
Xcel Energy	Agree	

4. Do you agree with the method of dispute resolution provided in Attachments 1, 2 and 3? If not, please explain in the comment area what would be more appropriate.

Summary Consideration: Most commenters believed the dispute resolution process was too prescriptive or noted there were inconsistencies with the existence of dispute resolution processes in the regions. In response, the drafting team modified step 3; the resolution process is no longer defined to allow flexibility for the entities to settle areas of contention.

Organization	Yes or No	Question 4 Comment
Western Area Power Administration, Rocky Mountain Region (WACM)	Disagree	A little loose - could be better defined.
Response: The resolution process is no longer defined in order to provide some flexibility for the entities to settle areas of contention.		
American Transmission Company	Disagree	ATC does not agree with the inclusion of a dispute resolution process contained within a Reliability Standard. This drives too much into how entities should work with each other and is unnecessary for system reliability. ATC does not believe that there is sufficient data demonstrating that mutual agreement efforts are failing to a point that warrant such a detailed dispute resolution procedure.
Response: The resolution process is no longer defined in order to provide some flexibility for the entities to settle areas of contention.		
System Protection	Disagree	The TO's requirements (3rd bullet) should come before the Regional process because TO requirements are filed with FERC.
Response: The resolution process is no longer defined in order to provide some flexibility for the entities to settle areas of contention.		
FirstEnergy	Disagree	In general we do not agree with the specificity of steps within Attachments 1, 2 and 3. However, if explicit dispute resolution steps remain, the SDT should clarify the phrase "regional reliability organization". This phrase could be interpreted to mean what is now referred to as the Regional Entity (i.e. RFC, MRO, etc.) or a RTO/ISO organization.
Response: The resolution process is no longer defined in order to provide some flexibility for the entities to settle areas of contention.		
MRO - NERC Standards Review Subcommittee	Disagree	The attachments are part of the standard and the MRO NSRS is concerned that the second bullet in Article 3 of Attachments 1, 2, and 3 is a more detailed step than is necessary. A standard should say "what" instead of "how" as currently being reviewed by a NERC standard development initiative chaired by Gerry Cauley; he

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>recently gave a presentation titled “Developing Results-Based Standards” to the NERC Standards Committee (on 10/07/2009). The MRO NSRS believes the second bullet in Article 3 of the attachments should say that there must be a dispute resolution process in place, and not go into the detail of listing all the various types.</td></tr>
<tr><td colspan="3">Response: The drafting team agrees that the “what” should be the focus. The resolution process is no longer defined in order to provide some flexibility for the entities to settle areas of contention.</td></tr>
<tr><td>Y-W Electric Association, Inc.</td><td>Disagree</td><td>The dispute resolution process is merely mentioned in passing, not defined and specified. By alluding to but not defining a clear dispute resolution process, this standard will force what may already be a disagreement into becoming a huge fight over what the dispute resolution process will be and who gets to administer it. This language should either be clearly defined or removed entirely.</td></tr>
<tr><td colspan="3">Response: The resolution process is no longer defined in order to provide some flexibility for the entities to settle areas of contention.</td></tr>
<tr><td>Wisconsin Electric</td><td>Disagree</td><td>The formalized dispute resolution process is too prescriptive, and is not required for BES reliability. The entities have proven processes for working jointly to achieve the necessary coordination. This type of procedure is not appropriate in a reliability standard.</td></tr>
<tr><td colspan="3">Response: The resolution process is no longer defined in order to provide some flexibility for the entities to settle areas of contention.</td></tr>
<tr><td>Pepco Holdings, Inc - Affiliates (PH)</td><td>Disagree</td><td>The hierarchy of using the dispute resolution process specified in pre-existing agreements between interconnected parties, prior to defaulting to an RRO (RE) process, or to Transmission Owner facility connection requirements, seems sensible. However, the concept of having dispute resolution as part of a sequential step procedure with very specific time requirements for each step seems awkward, if not unmanageable. A dispute resolution process is often protracted and as such could significantly affect the time schedules for subsequent steps. In addition, the outcome of the dispute resolution process could lead to schedule changes which are in conflict with subsequent steps. We would recommend eliminating the specific timelines identified in Attachments 1, 2 & 3 and instead reference conformance to a mutually agreed upon scope and schedule for each data exchange and review step. In the event the entities cannot reach mutual agreement then parties enter into some resolution process. A reliability standard does not need to describe or define a dispute resolution process. If the SDT does not agree with removing these sections, then all references to regional reliability organization need to be replaced with Regional Entity, (Also see additional comments on the use of specific deadlines in the response to Question #3)</td></tr>
<tr><td colspan="3">Response: The resolution process is no longer defined in order to provide some flexibility for the entities to settle areas of contention. See the drafting team’s response to Question 3.</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
NextEra Energy Resources	Disagree	The language in the dispute resolution process is ambiguous using terms such as “mutually agreed upon.”
Response: The drafting team appreciates your comment and the Attachments have been modified, based on stakeholder comments, to allow more flexibility rather than adding greater specificity.		
NV Energy	Disagree	The procedure identified in Attachments 1, 2, 3 seems reasonable, however, in Attachment 3,The phrases “the Transmission Owner or Distribution Provider” and “the affected Transmission Owner or Distribution Provider” are used at least eight times in this Attachment, usually in the same sentence. This is very ponderous and at least a little hard to keep the difference between these entities straight because of the nearly identical wording. It may help to use phrases such as “the proposing TO/DP” for the entity that wants to make a change and “the affected TO/DP” for the entity that may be impacted by the proposed change.
Response: The drafting team appreciates your comment. The terms are spelled out to avoid confusion. In response to your concerns regarding proposing and affected, the drafting team has changed Attachment 3.		
Exelon	Disagree	We are not aware of any RRO dispute resolution process currently in place in RFC.
Response: The drafting team acknowledges that all RROs may not have dispute resolution processes and the attachments have been modified.		
Duke Energy	Disagree	We don’t understand the meaning of the third bullet: “If no regional organization resolution process is available, apply the Transmission Owner’s Facilities connection requirements.”
Response: The resolution process is no longer defined in order to provide some flexibility for the entities to settle areas of contention.		
ITC Holdings	Agree	We are not aware of any resolution processes at the Reliability organizations. Will these types of processes be developed?
Response: The drafting team appreciates your support. The drafting team is aware that some RCs and RROs have resolution processes and we suggest that you contact your specific reliability entities for details.		
RelaibilityFirst Corporation	Agree	Suggest adding “documentation of agreement between parties”
Response: The drafting team appreciates your support. The comment does not specify where the wording would be added. The drafting team considered using the alternate wording in step 6 of Attachments 1, 2 and 3; however the existing wording was determined to be adequate.		

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration	Agree	
Electric Market Policy	Agree	
Entergy Services	Agree	
Flathead Electric Co-op	Agree	
Georgia Transmission Corporation	Agree	
Luminant Power	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Northeast Power Coordinating Council	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
PNGC- Cowlitz PUD - Central Lincoln PUD group	Agree	
PSEG	Agree	
Puget Sound Energy	Agree	
SCE&G	Agree	
Southern Company Transmission	Agree	

Organization	Yes or No	Question 4 Comment
US Bureau of Reclamation	Agree	
Virginia Electric and Power Company	Agree	
Xcel Energy	Agree	

5. The Associated Documents section C of PRC-001-2 includes only “PRC-001-2 System Protection Coordination Supplementary Reference — September 2009.” Are there other documents that should be included as associated documents? If so, please list in the comment area each document name and explain why each should be included.

Summary Consideration: Most commenters did not note additional references. Several commenters referenced the NERC SPCS Technical Paper “NERC Technical Reference on Power Plant and Transmission System Protection Coordination”. The drafting team explained that although the noted document is a good resource for describing some of the generation and transmission protection issues, many portions of this NERC SPCS Technical Paper are not applicable to PRC-001-2 and the references to other issues such as frequency and voltage excursions, loadability, and stability could be misconstrued to be a part of this standard.

Organization	Yes or No	Question 5 Comment
Puget Sound Energy		The process of ensuring an entity is aware of any changes made to the supplemental references over time is unclear. Does the standard get revised and re approved? How are supplemental references used in determining compliance?
Response: The drafting team thanks you for your comment. Standards are not revised in conjunction with revisions made to reference documents; however, the NERC Standards Development Process requires that each standard be reviewed every 5 years. Supplemental references are not used to determine compliance; only the requirements and measures in the regulatory approved NERC Reliability Standards are mandatory and enforceable.		
Electric Market Policy	Disagree	Not aware of additional documents that should be referenced; however, suggest changing the language to be consistent with the Supplementary Reference disclaimer. Proposed language, “The following document presents useful information that may explain or facilitate implementation of standard PRC-001-2.”
Response: The drafting team believes that the proposed language does not significantly change or improve the disclaimer – and the disclaimer is added to all references that support reliability standards.		
NERC - Director of Event Analysis and Information Exchange	Disagree	There are other documents: The “NERC Technical Reference on Power Plant and Transmission System Protection Coordination,” which was prepared by the SPCS is currently awaiting approval by the NERC Planning Committee. That document provides a significant treatise on methods of coordination of generator and transmission system protection.

Organization	Yes or No	Question 5 Comment
Response: The drafting team thanks you for your comment and agrees that the recently approved NERC SPCS Technical Paper "Power Plant and Transmission System Coordination" is a good resource for describing some of the generation and transmission protection issues. Many portions of the NERC SPCS Technical Paper are not applicable to PRC-001-2 and the references to other issues such as frequency and voltage excursions, loadability, and stability could be misconstrued to be a part of this standard. The drafting team also chose not to include general references such as IEEE guidelines, manufacturer's application guides, textbooks, etc.		
Northeast Power Coordinating Council	Disagree	No other documents.
PNGC- Cowlitz PUD - Central Lincoln PUD group	Disagree	No others.
American Transmission Company	Disagree	
Duke Energy	Disagree	
E.ON U.S.	Disagree	
Entergy Services	Disagree	
Flathead Electric Co-op	Disagree	
Manitoba Hydro	Disagree	
National Grid	Disagree	
NERC Standards Review Subcommittee	Disagree	
NextEra Energy Resources	Disagree	
Northeast Utilities	Disagree	

Organization	Yes or No	Question 5 Comment
Oncor Electric Delivery	Disagree	
SCE&G	Disagree	
Southern Company Transmission	Disagree	
System Protection	Disagree	
PSEG	Agree	A “white paper” type document should be developed to help the TO’s and GO’s determine how to properly meet these requirements. The overall intent is to ensure that protective relay systems are properly coordinated between different entities. Communication and cooperation between entities is very important to meet the spirit of the standard. Local working groups and/or protection subcommittees, etc under the auspices of a specific region/RTO are appropriate places to develop and maintain these processes.
Response: Thank you for your comment concerning the need for a “white paper” which helps the Transmission Owners and Generation Owners determine how to properly perform System Protection Coordination. The drafting team agrees that communication and cooperation between entities is important. The Drafting team believes that the processes outlined in the attachments of PRC-001-2 can be easily followed by the entities to maintain the process of communications between each other.		
Virginia Electric and Power Company	Agree	Agree, know of no other documents that should be included
Response: The drafting team thanks you for your comments.		
ITC Holdings	Agree	The “System Protection Coordination” definition refers to the NERC Transmission Planning Standards (TPL). These applicable sections should be included in the reference.
Response: Thank you for your comment that the sections of the TPL Standards should be included as a reference to this standard. The definition of System Protection Coordination has been modified to specifically make reference to “Table 1 – Steady State & Stability Performance Planning Events of the NERC Transmission Planning (TPL) reliability standards.”		
Georgia Transmission Corporation	Agree	FAQ to help with the most common questions.
Response: The drafting team thanks you for your comment. The drafting team believes that a FAQ document is not necessary because the most		

Organization	Yes or No	Question 5 Comment
common questions will be addressed through the commenting process and the resulting modifications to the standard.		
RelaibilityFirst Corporation	Agree	I am not aware of any other documents.
Response: The drafting team thanks you for your comments.		
US Bureau of Reclamation	Agree	In the case of WECC, a white paper was published on what elements would fit in the term "Protection System".
Response: The drafting team thanks you for your comment concerning the WECC white paper published on what elements fit the term “Protection System.” The drafting team believes that the interpretation of that term or redefining the term “Protection System” is beyond the scope of this drafting team.		
Bonneville Power Administration	Agree	
NV Energy	Agree	
Pepco Holdings, Inc - Affiliates (PH)	Agree	
Western Area Power Administration, Rocky Mountain Region (WACM)	Agree	
Wisconsin Electric	Agree	
Y-W Electric Association, Inc.	Agree	
Luminant Power	Agree	No other documents
Exelon	Agree	The paper written by members of the NERC SPCS (System Protection and Control Subcommittee), Power Plant and Transmission System Coordination should be included as a reference document for the standard once it is approved by the NERC Planning Committee. This paper provides the technical basis to assure that the generator relay elements listed in the current supplementary reference document do coordinate.
Response: The drafting team thanks you for your comment and agrees that the recently approved NERC SPCS Technical Paper “Power Plant and		

Organization	Yes or No	Question 5 Comment
Transmission System Coordination" is a good resource for describing some of the generation and transmission protection issues. Many portions of the NERC SPCS Technical Paper are not applicable to PRC-001-2 and the references to other issues such as frequency and voltage excursions, loadability, and stability could be misconstrued to be a part of this standard. The drafting team also chose not to include general references such as IEEE guidelines, manufacturer's application guides, textbooks, etc.		
FirstEnergy	Agree	We encourage the standard drafting team to consider inclusion of the "Power Plant and Transmission System Protection Coordination" that is presently in development by the NERC System Protection and Control Subcommittee.
Response: The drafting team thanks you for your comment and agrees that the recently approved NERC SPCS Technical Paper "Power Plant and Transmission System Coordination" is a good resource for describing some of the generation and transmission protection issues. Many portions of the NERC SPCS Technical Paper are not applicable to PRC-001-2 and the references to other issues such as frequency and voltage excursions, loadability, and stability could be misconstrued to be a part of this standard. The drafting team also chose not to include general references such as IEEE guidelines, manufacturer's application guides, textbooks, etc.		
Xcel Energy	Agree	We feel the NERC technical reference document titled "Power Plant and Transmission System Protection Coordination" should also be listed.
Response: The drafting team thanks you for your comment and agrees that the recently approved NERC SPCS Technical Paper "Power Plant and Transmission System Coordination" is a good resource for describing some of the generation and transmission protection issues. Many portions of the NERC SPCS Technical Paper are not applicable to PRC-001-2 and the references to other issues such as frequency and voltage excursions, loadability, and stability could be misconstrued to be a part of this standard. The drafting team also chose not to include general references such as IEEE guidelines, manufacturer's application guides, textbooks, etc.		

6. The SDT has included VRFs with this posting. Do you agree with the assignments made? If not, please explain in the comment area.

Summary Consideration: Most commenters suggested the VRFs for the requirements should be "Lower". The drafting team agreed that Requirement R4 is administrative in nature and changed the VRF from "Medium" to "Lower." The drafting team disagreed with commenters who suggested that Requirements R5 and R6 should be "Lower" and left the VRFs assigned as "Medium". One commenter suggested the VRFs for Requirements R2 and R3 should be "High" but the drafting team disagreed and left the VRFs unchanged at "Medium".

Organization	Yes or No	Question 6 Comment
E.ON U.S.	Disagree	R4 and R6 should be low risk. If data availability can be a month or more, then this would seem to suggest Medium Risk is too high
Response: After consideration of your comments, the drafting team agrees that R4 is primarily administrative in nature and has set the VRF to Lower. **The drafting team selected the Medium VRF for R5 & R6 because the Transmission Operator and Generator Operator requires a basic knowledge of the system they operate including relay scheme types that could directly affect the Bulk Electric System but is unlikely to lead to bulk power system instability. A low VRF would indicate a requirement that is administrative in nature and the drafting team believes this requirement exceeds that level. The time frame was set to make sure that this information was passed to the operator in an appropriate time frame.**		
System Protection	Disagree	1) The VRF with respect to the DP in R3 through R5 should be Low because the lesser BES significance of connections at the distribution level. 2) The VRF for R5 and R6 should be Low for all entities because TOP and GOP already have familiarity from PRC-001-1 R1. 3) The VRF for R4 should be Low because one month is a very short time in the Planning time horizon.
Response: 1) The drafting team believes that the VRFs for R3, R4 (see below), & R5 are set appropriately and the only applicability to Distribution Providers is for those that own transmission Protection Systems. **2) The drafting team believes that the VRFs for R5 & R6 are set appropriately. The new requirements contain more details and address new systems and other technical information requests from the Transmission Operator or Generator Operator.** **3) After consideration of all comments, the drafting team agrees that R4 is primarily administrative in nature and has set the VRF to Lower.**		
PSEG	Disagree	I am still unsure of the intent in R5. From what I can see in the proposed standard, the TO's are responsible

Organization	Yes or No	Question 6 Comment
		to educate the TOP's in its protective relay philosophies. I do not think this will have much impact on the overall reliability of the system, and I feel this should be a VRF of Low.
Response: The drafting team believes that the VRF for R5 is set appropriately. The intent of the requirement is to ensure that the actual personnel performing the Transmission Operator function are familiar with the purpose and limitations of the Protection System schemes applied in its area so that the Transmission Operator can perform its prescribed responsibilities, which is more than an administrative function.		
Flathead Electric Co-op	Disagree	Not sure. **Response: See other responses to this question. Perhaps they will address your concerns.**
Exelon	Disagree	R1 covers existing systems; VRFs should be the same for new systems as well as existing systems. All VRFs should be at the lower status.
Response: The drafting team set the Lower VRF for R1 because we believe this function to be more administrative in nature and was being done to allow entities to request setting information on existing settings where coordination has already been performed. After consideration of all comments, the drafting team agrees that R4 is primarily administrative in nature and has set the VRF to Lower **The drafting team believes the VRFs for the remaining requirements are appropriately set to Medium.**		
MRO - NERC Standards Review Subcommittee	Disagree	Since much of this standard requires that documentation be transferred between parties, the MRO NSRS believes the VRF should be "Low" for the requirements that require sharing of documentation (Articles R4, R5, and R6).
Response: After consideration of all comments, the drafting team agrees that R4 is primarily administrative in nature and has set the VRF to Lower. **The drafting team selected the Medium VRF for R5 & R6 because the Transmission Operator and Generator Operator requires a basic knowledge of the system they operate including relay scheme types that could directly affect the Bulk Electric System but is unlikely to lead to bulk power system instability. A low VRF would indicate a requirement that is administrative in nature and the drafting team believes this requirement exceeds that level.**		
FirstEnergy	Disagree	We feel that the SDT should consider a HIGH VRF for Requirements R2 and R3. A requirement in the planning time frame with a HIGH VRF is defined as "one that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition." Violating Requirements R2 and R3 could lead to a miscoordination that could cause part of the BES to trip which could lead to instability and cascading.

Organization	Yes or No	Question 6 Comment
Response: The drafting team believes the VRFs for R2 & R3 are set appropriately at Medium.		
Puget Sound Energy	Agree	Agree generally. When the VRF is at the end of a sub requirement sentence and not at the end of the respective requirement it appears that only the sub requirement has a risk (i.e., R2.4 versus R2). Unsure if that is intent. Unsure why R1 would be VRF of Lower and R4 would be VRF of Medium.
Response: The drafting team has modified the standard to reflect your comment regarding the location of the VRFs. **After consideration of all comments, the drafting team agrees that R4 is primarily administrative in nature and has set the VRF to Lower.**		
Y-W Electric Association, Inc.	Agree	The VRFs seem to make sense.
Response: The drafting team thanks you for your comment.		
ITC Holdings	Agree	none
American Transmission Company	Agree	
Bonneville Power Administration	Agree	
Duke Energy	Agree	
Electric Market Policy	Agree	
Entergy Services	Agree	
Georgia Transmission Corporation	Agree	
Luminant Power	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	

Organization	Yes or No	Question 6 Comment
NextEra Energy Resources	Agree	
Northeast Power Coordinating Council	Agree	
Northeast Utilities	Agree	
NV Energy	Agree	
Oncor Electric Delivery	Agree	
Pepco Holdings, Inc - Affiliates (PH)	Agree	
PNGC- Cowlitz PUD - Central Lincoln PUD group	Agree	
RelaibilityFirst Corporation	Agree	
SCE&G	Agree	
Southern Company Transmission	Agree	
US Bureau of Reclamation	Agree	
Virginia Electric and Power Company	Agree	
Western Area Power Administration, Rocky Mountain Region (WACM)	Agree	
Wisconsin Electric	Agree	

7. The SDT has provided an Implementation Plan with this posting. Do you agree with the implementation time frames? If not, please explain in the comment area.

Summary Consideration: Most responders agreed with the Implementation Plan; therefore, no changes were made. A few commenters suggested that the "three months after applicable regulatory approval" be replaced with "six months after applicable regulatory approval". The drafting team disagreed stating that facility owners should already be supplying this information to associated operating entities to meet existing Requirement R1 of PRC-001-1.

A few commenters disagreed primarily with the time frames specified in Requirements R5, Part 5.1 and R6, Part 6.1. The intention of those requirements is to provide the Transmission Operator and Generator Operator with information on schemes applied on a general basis; therefore, the drafting team believes the time frames for Requirements R5, Part 5.1 and R6, Part 6.1 are appropriate. Note that the existing standard, PRC-001-1, Requirement R1 requires each TOP, BA and GOP to "be familiar with" the purpose and limitations of protection system schemes applied in its area; consequently, facility owners should already be supplying this information to associated operating entities to meet the existing requirement.

Organization	Yes or No	Question 7 Comment
System Protection	Disagree	1) Please revise R1 so that it's clear this is forward looking and there is no PRC-001-2 instigated obligation to request. The pertinent information was generally exchanged years or decades ago when these facilities were built. 2) In A.5 the retirement of provisions R5 5.1 and R6 6.1 after 6 years imply a phased-in approach for informing TOP and GOP, but seem to conflict with the "no later than 6 months" language in R5 5.1 and R6 6.1 themselves.
Response: 1. Requirement R1 does not obligate owners to request information. It will only apply to requests for information after the standard becomes effective. 2. Requirements R5, Part 5.1 and R6, Part 6.1 are not phased-in but require actions to be concluded within six months of the effective date of the standard. The drafting team realizes that these Parts of the two requirements will no longer be necessary once all information is initially provided.		
Southern Company Transmission	Disagree	It is suggested that the proposed effective date be six months after BOT adoption rather than three months after BOT adoption to provide additional buffer for accomplishing the requirements under 6.1 for the number of generators in our company.
Response: The existing standard, PRC-001-1, requires (R1) each TOP, BA and GOP to "be familiar with" the purpose and limitations of protection system schemes applied in its area – so facility owners should already be supplying this information to associated operating entities to meet existing Requirement R1. Therefore the drafting team believes this effective date is appropriate. Additionally, Requirement R6, Part 6.1 allows for another six		

Organization	Yes or No	Question 7 Comment
months after the effective date of the Standard.		
PSEG	Disagree	R5.1 needs more clarification. What is the format for this data? Is the TOP expecting a write-up on each interconnection line? Are they expecting a write-up of how all of the specific relay schemes work? What does “limitations” mean? The TO can tell the TOP what schemes are employed on their system. However, the onus should be on the TOP to understand the basics of how the schemes work and what the purpose of the schemes are. In any case, the TOP needs to let the TO’s know how the “operating decisions” might be affected by the specific relay scheme. This will help the TO supply the correct data to the TOP. Without further clarification of R5.1, we do not agree with the implementation plan time frame.
Response: The drafting team thanks you for your comment. The intention of Requirement R5, Part 5.1 is to provide the Transmission Operator with information on schemes applied on a general basis. Therefore, there could be a single description of an entity’s Directional Comparison Blocking (DCB) scheme, Permissive Overreaching Transfer Trip scheme, etc. “Limitations” refers to conditions that may cause the Protection System to not operate or to operate incorrectly or undesirably. For example, if the carrier equipment is out of service for a Directional Comparison Blocking (DCB) scheme, you could expect the Protection System to over trip for external faults unless actions were taken to disable the communications-aided scheme. Another example might be the need to disable a bus differential if one of its supplying CTs has failed.		
US Bureau of Reclamation	Disagree	1. The implementation needs to address the situation when a new Owner or Operator registers as entities. The requirements 5.1 and 6.1 should be revised to reflect that condition. 2. In addition the language in R1 and R2 should also be modified to be concise.
Response: 1. The drafting team believes this issue is addressed by Requirement R5, Part 5.3 and Requirement R6, Part 6.3 of the Standard. 2. The drafting team believes the language in Requirements R1 and R2 is appropriate.		
NextEra Energy Resources	Disagree	1. The implementation plan does not take into consideration how the same entity with multiple functions would be required to supply data. Does the action of supplying data have to be formalized in this situation and would failure to comply require self reporting? 2. Also, it is unclear how partial ownership in an asset would be addressed and the responsibilities for the limited and majority owners.
Response: 1. The drafting team believes that all the requirements apply to all applicable registered entities. The act of supplying data should be documented in some manner for record keeping and compliance purposes. 2. Joint ownership issues would need to be addressed consistent with other standards that apply to the facility through some mutually agreed to or contractual arrangement between the owners.		

Organization	Yes or No	Question 7 Comment
Pepco Holdings, Inc - Affiliates (PH)	Disagree	1. The implementation plan is acceptable with the exception of the timeframes associated with Section 5.1. This section requires the Transmission Owner or Distribution Provider to provide to its Transmission Operator the general descriptions, purposes and limitations of the existing types of transmission Protection System schemes applied on its system within 6 months following the effective date of the Standard. This requirement is very vague as to what specific data is required. One might interpret this to mean providing information such as: Line xyz is protected by a primary POTT pilot scheme and a 3 zone distance back-up scheme, with an X MVA steady state relay load limit. Someone else might interpret this to mean having to supply much more detailed scheme descriptions, including relay communication channel descriptions, zone distance relay reaches, clearing times and load limits for each protective zone or element, as well as detailed instructions as to what action to take for a failure of each protective system component. Additional clarification or specific examples of what is expected should be provided. 2. Also the term “transmission Protection Schemes applied on its system” implies supplying data for all transmission schemes on their system regardless of whether they are associated with BES or non-BES facilities, or whether they are installed on facilities for which the Transmission Operator is not responsible. Section 4.2 should be revised to prescribe applicability to BES facilities. 3. Due to the uncertainty surrounding the extent of the data required to be supplied, the present 6 month time frame should be extended to at least 12 months. This time frame could be refined on subsequent drafts once the scope of this data submittal is better defined.
Response: 1.The drafting team believes the time frame for Requirement R5, Part 5.1 is appropriate. The intention of Requirement R5, Part 5.1 is to provide the Transmission Operator with information on schemes applied on a general basis. Therefore, there could be a single description of an entity’s Directional Comparison Blocking (DCB) scheme, Permissive Overreaching Transfer Trip scheme, etc. “Limitations” refers to conditions that may cause the Protection System to not operate or to operate incorrectly or undesirably. For example, if the carrier equipment is out of service for a Directional Comparison Blocking (DCB) scheme, you could expect the Protection System to over trip for external faults unless actions were taken to disable the communications-aided scheme. Another example might be the need to disable a bus differential if one of its supplying CTs has failed. The PRC-001-2 System Protection Coordination Supplementary Reference — September 2009 document provides guidance on what types of information will be expected. **2. The drafting team avoided the term Bulk Electric System in the Applicability section of the standard since at present there is no consensus among the Regional Reliability Organizations. The drafting team determined that this standard is applicable to Transmission Owners, Generator Owners and Distribution Providers according to the NERC Glossary of Terms that clearly defines these entities in all NERC Regional Reliability Organizations. The various owners have to register with NERC as one of these three types of entities.** **3. The drafting team believes the time frame for Requirement R5, Part 5.1 is appropriate.**		
NERC - Director of Event	Disagree	The Implementation Plan should be modified to recognize the time necessary to review the protection

Organization	Yes or No	Question 7 Comment
Analysis and Information Exchange		coordination of all existing generation, not just new units, modifications to units, or on a “upon request” basis. See comments in Question 10.
Response: PRC-001-2 does not require the coordination review of all existing generation; however, it does allow entities to request information for those interconnected Facilities they believe review is necessary.		
Electric Market Policy	Disagree	The Implementation Plan states the following regarding retirement dates for existing PRC-001-1 Requirements R2, R5 and R6: “Requirements R2, R5 and R6 due to their dependency on prerequisite approvals will be retired the latter of the following dates - when PRC-001-2 or the associated standards TOP-001-2, TOP-003-1 and IRO-010-1 become effective. “ Depending on the timing associated with the TOP standards, there could be requirements in two versions of PRC-001 that are enforceable. How will this be implemented?
Response: As noted in the Implementation Plan the associated Standards are scheduled to be FERC approved and effective prior to the approval of this Standard. NERC will monitor the status and coordinate. Only one version of PRC-001 will be effective at any one time.		
Georgia Transmission Corporation	Disagree	There may be a conflict between the three months after approval of the standard and the six months for transfer of information.
Response: These time periods are sequential and do not represent a conflict. “The standard shall become effective on the first day of the first calendar quarter, three months after BOT adoption” is common language used in many Reliability Standards. Additionally, Requirement R6, Part 6.1 allows for another six months after the effective date of the Standard.		
FirstEnergy	Disagree	We feel that the implementation time frame of 3 months after applicable approvals is too short. This standard is creating a significant shift in applicable entities (from Operators to Owners) and the Owners must have enough time to coordinate compliance with these requirements for which they were previously not responsible. We feel that a time frame of 12 months is more appropriate.
Response: The existing standard, PRC-001-1, requires (R1) each TOP, BA and GOP to “be familiar with” the purpose and limitations of protection system schemes applied in its area – so facility owners should already be supplying this information to associated operating entities to meet existing Requirement R1. Therefore the drafting team believes this effective date is appropriate.		
Western Area Power Administration, Rocky Mountain Region (WACM)	Agree	Thanks for removing R2, R5 and R6

Organization	Yes or No	Question 7 Comment
Response: The drafting team appreciates your support.		
ITC Holdings	Agree	none
NERC Standards Review Subcommittee	Agree	None.
American Transmission Company	Agree	
Bonneville Power Administration	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entergy Services	Agree	
Exelon	Agree	
Luminant Power	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Northeast Power Coordinating Council	Agree	
Northeast Utilities	Agree	
NV Energy	Agree	
Oncor Electric Delivery	Agree	

Organization	Yes or No	Question 7 Comment
PNGC- Cowlitz PUD - Central Lincoln PUD group	Agree	
Puget Sound Energy	Agree	
RelaibilityFirst Corporation	Agree	
SCE&G	Agree	
Virginia Electric and Power Company	Agree	
Wisconsin Electric	Agree	
Y-W Electric Association, Inc.	Agree	

8. If you aware of any regional variances that would be required as a result of this standard, please identify the regional variance.

Summary Consideration: There were no valid regional differences identified as they pertain to this standard. Two comments identified a dispute resolution process within the NPCC region as a regional variance. The drafting team addressed the dispute resolution process in Question 4.

Organization	Question 8 Comment
PNGC- Cowlitz PUD - Central Lincoln PUD group	Aware of none.
Response: The drafting team thanks you for your comment.	
ITC Holdings	ITC Holdings is not aware of any regional variances that would be required.
Response: The drafting team thanks you for your comment.	
Luminant Power	NA
Duke Energy	None
NV Energy	none
NERC Standards Review Subcommittee	None.
Wisconsin Electric	None.
Bonneville Power Administration	Not aware of any regional variances:
Response: The drafting team thanks you for your comment.	
National Grid	NPCC Regional Variance: The dispute resolution process would involve either the ISO-NE or NYISO not the NPCC (reference: Attachments 1, 2, and 3 Step 3, bullet point 2, term “regional reliability organization”).

Organization	Question 8 Comment
Response: The resolution process is no longer defined to provide some flexibility for the entities to settle areas of contention.	
Northeast Power Coordinating Council	NPCC Regional Variance: The dispute resolution process would involve either the ISO-NE or NYISO, not the NPCC. This is in reference to Step 3, bullet 2, in each of Attachments 1, 2, and 3, referring to the regional reliability organization.
Response: The resolution process is no longer defined to provide some flexibility for the entities to settle areas of contention.	
Pepco Holdings, Inc - Affiliates (PH)	PHI is not aware of any regional variances
Response: The drafting team thanks you for your comment.	
Georgia Transmission Corporation	Regions define the BES differently.
Response: The drafting team thanks you for your comment. The BES is not referenced in PRC-001-2; therefore the difference in regional definitions does not impact this standard.	
Virginia Electric and Power Company	The standard should indicate the protection systems that are included within the scope of this standard. Suggest the scope be defined as all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System, as defined by the Regional BES
Response: The drafting team thanks you for your comment. The standard addresses generation and transmission Protection Systems associated with the interconnections between entities that may affect the System Protection Coordination. The drafting team believes that using the phrase 'affecting the reliability of the Bulk Electric System' would cause inconsistency between Regions.	
Y-W Electric Association, Inc.	We are not aware of any regional variances that would be required.
Response: The drafting team thanks you for your comment.	

9. If you are aware of any conflicts between the proposed standard(s) and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify the conflict.

Summary Consideration: The majority of responders stated there were no identified conflicts. One commenter identified a possible conflict regarding the applicability of Distribution Providers which was addressed in Question 1.

Several comments were received regarding potential conflicts with "business agreements/contractual agreements" made between entities. The drafting team addressed these comments by adding the following introductory sentence in Attachments 1-3:

"This attachment does not preclude the need to follow other established requirements, tariffs, contracts or agreements in addition to the requirements in the standard."

Organization	Question 9 Comment
National Grid	Potential conflicts with the "business agreements/contractual agreements" made between entities especially with Generator Interconnection agreements where several levels of technical evaluations are required.
NextEra Energy Resources	Potential conflicts with the "business agreements/contractual agreements" made between entities especially with Generator Interconnection agreements where several levels of technical evaluations are required.
Northeast Power Coordinating Council	Potential conflicts with the "business agreements/contractual agreements" made between entities especially with Generator Interconnection agreements where several levels of technical evaluations are required.
Response: The drafting team thanks you for your comment. The revised standard does not preclude the need to follow other established requirements, tariffs, contracts or agreements.	
Electric Market Policy	There is usually an Interconnection Agreement between each generator and the owner of the interconnection whether that belongs to a Transmission Owner or Distribution Provider. We are unsure as to whether there are conflicts. Should the standard state that where there are conflicts the standard takes precedence?
Response: The drafting team thanks you for your comment. The revised standard does not preclude the need to follow other established requirements, tariffs, contracts or agreements.	
E.ON U.S.	Generators will continue to supply current until a facility limit is reached. Outside of the limit (fault or not), a Generator will be protected as indicated per ANSI requirements.

Organization	Question 9 Comment
Response: The intent or PRC-001-2 is to ensure interconnected entities coordinate their protection settings and pass sufficient information between themselves to do that. The drafting team agrees that a generator should not be operated beyond its ANSI or manufacturer's requirements and should be protected accordingly. Those operating limits and any other limits that are particular to a unit should be communicated to the applicable Transmission Planner, Transmission Owner, and Planning Coordinator.	
Georgia Transmission Corporation	Check carefully there are no conflicts with NUC-001 and also the TPL standards.
Response: The drafting team does not see a conflict between PRC-001-2 and the referenced standards related to System Protection Coordination. It is acknowledged that in some cases one standard may have elements that are more stringent than another, e.g. data retention.	
Virginia Electric and Power Company	CIP standards prevent sharing of information among entities for Critical Assets, and this standard requires sharing of this same information, which would be in conflict. How can this be resolved?
Response: The drafting team appreciates your concern regarding cyber security; however, certain information must be shared in order to design and set Protection Systems. The drafting team does not believe that providing any of the Protection System information indicated in the draft standard would violate the CIP standards.	
ITC Holdings	ITC Holdings is not aware of any conflicts.
Response: The drafting team thanks you for your comment.	
System Protection	Conflict: Section A.4.1.3 could conflict with state regulatory requirements regarding generation connection at the distribution level.
Response: The drafting team thanks you for your comment, The standard has been modified to remove the reference in the applicability section for Distribution Providers that said, "or that interconnect with Generator Owners."	
Luminant Power	NA
Duke Energy	None
Entergy Services	None identified.
NERC Standards Review	None.

Organization	Question 9 Comment
Subcommittee	
PNGC- Cowlitz PUD - Central Lincoln PUD group	None.
Wisconsin Electric	None.
Bonneville Power Administration	not aware of any conflicts
Pepco Holdings, Inc - Affiliates (PH)	PHI is not aware of any conflicts
Y-W Electric Association, Inc.	We are not aware of any conflicts.
Response: The drafting team thanks you for your comment.	

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

Summary Consideration: The majority of the comments received in Question 10 were repeats of those received and addressed in Questions 1 through 9. A number of additional comments resulted in the changes to the Purpose, several requirements, and the Attachments. Those changes are noted below:

- Purpose – Clarified by adding the verbiage "between interconnected functional entities."
- Requirement R1 – Clarified the scope to only direct interconnection Protection System settings and scheme types.
- Requirements R2 & R3 – Clarified determination of what changes not on the interconnected Facilities impact System Protection Coordination
- Requirements R2 & R3 – Revised language to be more specific regarding functional entity applicability
- Attachments (all) – Added Step 7 to document changes made during commissioning that impact System Protection Coordination

Organization	Question 10 Comment
CenterPoint Energy	1. PRC-001-1 is an example of an overly prescriptive and unnecessary process-based reliability standard. PRC-001-1 contains only low-level facilitating requirements that are more appropriately and inherently monitored under various higher-level, performance-based standards (also referred to as results-based standards). Based on existing NERC standards and current projects, CenterPoint Energy recommends retiring PRC-001. The relevant requirements in the existing PRC-001-0 deal with operational issues and are being addressed by the drafting teams for TOP-001-2, TOP-003-1, and IRO-010-1. 2. The various aspects contained in PRC-001-1 are already addressed or are being addressed in existing NERC standards and other active projects. The PRC-024-1 Generator Frequency and Voltage Protective Relay Setting (2007-09) project proposes specific relay setting criteria for generator protection that provides for a coordination margin with other protection systems. Underfrequency Load Shedding Program Requirements (2007-01) also proposes to include specific relay setting criteria. In addition, existing standard PRC-004 Analysis and Mitigation of Transmission and Generation Protection System Misoperations requires system-wide action to address relay Misoperations, which would include relay coordination issues. Existing NERC standards FAC-001 Facility Connection Requirements and FAC-002 Coordination of Plans for New Facilities also include requirements related to those in PRC-001-1.
Response: 1. The drafting team disagrees. PRC-001-2 is the only NERC Reliability Standard that addresses System Protection Coordination between Transmission Owners, Generation Owners and Distribution Providers that own transmission Protection Systems. The real-time requirements that were included in PRC-001-1 are being addressed by other drafting teams and are not included in PRC-001-2. **2. The drafting team agrees that those Protection System issues already addressed or proposed to be addressed in other standards are not included in PRC-001-2. However, we disagree that PRC-004-1 addresses all System Protection Coordination issues simply because it covers relay**	

Organization	Question 10 Comment
Misoperations.	
Manitoba Hydro	It is a positive move by the Standard Drafting team to move previous requirements R2, R5 and R6 of PRC-001-1 which dealt with mainly operational issues into more appropriate standards.
Response: The drafting team appreciates your support.	
Southern Company Transmission	1) I have a "General" concern about this proposed standard, as follows: The Standard is comprised of 6 Requirements. Requirement 2 applies to "Generator Owners", and specifies that Generator Owners must execute "Attachment 1" when the conditions in the sub-requirements are met. HOWEVER - Steps 2, 3, 5, and 6 in Attachment 1 must be performed by Transmission Owners and Distribution Providers, so these steps are actually "requirements" for TOs and DPs. THEREFORE - It appears to me that the Standard needs to be updated to reflect the fact that Requirement 2 applies to TO and DP as well as GO. By the same logic, the Standard needs to be updated to reflect the fact that Requirement 3 applies to GO as well as TO and DP.A Final Question: How will auditors address these "Attachment Requirements" in the future? Specifically, will an audit team ask me to demonstrate Compliance with "PRC-001-2 Requirement 2 Attachment 1 Step 5"? That's starting to sound a little bit complicated! 2) 5.1 Change "No later than six months following the effective date of the Standard" to "No later than one year following the effective date of the Standard" PRC-001 Attachment 2 Conditions: Change "At least six months prior to the proposed in service date of any of the following" to "At least six months prior to the proposed in service date or according to an agreed upon schedule of any of the following: All of the deadlines in this document bother me because it is something that someone will have to keep up with for design and construction projects. We work a lot of projects at Generating Plants and transmission substations with tie lines in Southern Company. I can see where a deadline can easily be missed. Also, construction projects are commonly moved around on schedules for efficient use of resources. This may take away some of that flexibility. Scoping changes that comes up during the middle of design projects will need to be reviewed for impact to SERC compliance coordination deadlines. Again, this is something else that we will need to start keeping documentation on just for SERC compliance. In my view, it is a poor use of resources. 3) The proposed standard requirements included in R2, R3, and R4, with their associated attachments and timelines contained therein, seem to make something already being done successfully between generation and transmission in our company an excessively burdensome process. We feel that the specificity of these requirements will cost a great deal and gain little or no benefit to coordination. Perhaps the standard requirements could be simplified to: “The Protective Systems at the interface of generation and transmission (and between adjoining transmission entities) shall coordinate.” 4) General comment on R6: It has been a rare occasion for the Generator Operator to request generator protective relay settings from those who set the relays. It is not clear (to us) why the GOP needs the settings. Providing the settings to the GOP settings specified in R6.1 and R6.2 is not valuable. For coordination of the generator relays with the transmission system relays, the TOP or TO would need to know these settings rather than the GOP. R5 and R6 both seem to be

Organization	Question 10 Comment
	directed towards operational issues rather than system protection coordination issues. These operations issues may be better placed in an IRO standard than in a PRC standard. Any provision of supplying information about generator or transmission Protection System schemes (if supplied to the GOP [R6] or TOP [R5] should be in response to a request rather than being a blanket requirement for all GOs and TOs. We foresee a lot of work which will result from R6 (and R5) requirements that may never be reviewed and therefore be wasted effort.
Response: **1. The drafting team has modified Requirements R2 and R3 of the standard to clarify the actions of the registered entities. The drafting team cannot speak on behalf of any compliance group.** **2. The drafting team believes that the time as specified in Requirement R5, Part 5.1 is adequate. Also, the drafting team has modified the Attachments associated with Requirements R2 and R3 so that those deadlines can change with the mutual agreement of all entities.** **3. The drafting team believes that the requirements and associated attachments of this Standard provide adequately detailed steps that will help the affected Functional Entities accomplish Protection System Coordination. Simplifying the requirements as you suggest would still necessitate documentation of the process. Without more detailed steps, there will be less consistency in accomplishing Protection System Coordination throughout the industry.** **4. The purpose of Requirements R5 and R6 is to ensure that real-time operating personnel have the information needed to react to the operations of Protection Systems. These requirements don't necessitate providing detailed relay settings, but rather general information about how protective schemes on the respective systems function.**	
Portland General Electric Co.	1. The Purpose of the standard does not make it clear that the real-time aspects of this standard only apply to certain requirements. This should be broken into three different purposes that correspond to the different sets of requirements. 2. It is not clear why there are the three different attachments. It would be simpler to implement if there were only one attachment that was sufficiently general to apply to all the different instances.
Response: **1. The drafting team believes that the Purpose statement adequately reflects the intent of this standard.** **2. The drafting team created three different attachments to show the interaction between Functional Entities from each Functional Entity's perspective. Although the bulk of these three attachments are similar, subtle differences exist. The drafting team believes that combining the Attachments into one would be more confusing.**	
Wisconsin Electric	1. The Purpose of this standard should be revised: "To ensure that System Protection Coordination is achieved with neighboring entities and that operating and planning personnel have necessary Protection System information to assure reliability of the BES."

<table>
<tr><th>Organization</th><th>Question 10 Comment</th></tr>
<tr><td></td><td>2. The standard should be clarified such that requirements for information apply ONLY to interconnection-related facilities of neighboring systems that are registered entities, AND where coordination is required for BES reliability.

3. Requirements R5 and R6 should be deleted. These requirements are unnecessary and duplicative. System owners and operators already work cooperatively to assure reliability.</td></tr>
<tr><td colspan="2">Response:
1. The drafting team thanks you for your comment and we have modified the Purpose statement for clarity by adding the phrase, “between interconnected functional entities.”
2. The drafting team thanks you for your comment and we have modified the Purpose statement for clarity. The drafting team believes that referencing BES reliability would cause inconsistency between Regions.
3. The drafting team disagrees and maintains that information sharing with Transmission and Generation Operators as outlined in Requirements R5 and R6 are necessary to ensure that informed operating decisions are made by the Transmission and Generation Operators.</td></tr>
<tr><td>System Protection</td><td>1) We applaud the SDT for considerably improving and clarifying PRC-001 via this draft and their Supplementary Reference.

2) The “Description of Current Draft” mentions R7 but it’s not in the draft itself.

3) PER-005-1 does not apply to Generator Operators. Is there a project to expand its applicability?

4) What is the intent of A.4.1.3 regarding DP that interconnect with GO? Is this for generation outlet only, or does it include station service supply?

5) Attachment 1, Step 1, last bullet: Insert “electrical” before protective.

6) Attachment 1, Step 5: a) Respond to GO, not GOP; b) this may not leave sufficient time for commissioning tests before the desired in-service date.

7) All Attachments, Step 6: Strengthen wording to be crystal clear that facilities must not go in service until agreed to Protection System changes are complete.

8) All Attachments, Step 5: An entity’s response regarding adequacy must not create liability for the reviewing party.

9) Attachments 2 & 3, Step 1, 8th bullet: Insert “electrical” before protective.

10) Remove Device 79 and “reclose” from the Supplementary Reference because reclosing performs a control, not a protective function (see IEEE Std C37.2 and IEEE dictionary).</td></tr>
<tr><td colspan="2">Response:</td></tr>
</table>

Organization	Question 10 Comment
1. The drafting team appreciates your support. **2. This was a typo and has been corrected to R6.** **3. This question is outside of the scope of this drafting team. Please refer your question to the NERC Standards Committee.** **4. Section 4.1.3 has been modified to read "Distribution Providers that own transmission Protection Systems".** **5. The drafting team has modified this bullet to "Protection Systems" which is a defined term.** **6. The drafting team agrees that step 5 should refer to the Generator Owner, not the Generator Operator. The Standard has been modified accordingly. Regarding the schedule in Attachment 1, Step 5, the standard was revised so that Functional Entities can establish their own schedule as long as it is agreed upon.** **7. The drafting team believes that the existing wording is strong enough to address your concerns.** **8. The drafting team understands your concern, but believes that legal issues need to be addressed between the Functional Entities involved.** **9. The drafting team has modified this bullet to "Protection Systems" which is a defined term.** **10. The drafting team disagrees and believes that a reclosing scheme is a design and setting issue that needs to be included in the exchange of information described in the Supplementary Reference and in Attachments 2 & 3.**	
National Grid	a. Having timelines as required by the proposed draft of the standard does not enhance reliability of the bulk power system by itself. It is an information sharing mandate that requires entities to share timely and accurate information among themselves. The proposed standard addresses a communications issue not a reliability issue. b. No reference has been made to the CIP Information Sharing standard that addresses how to handle critical infrastructure protection internally and externally. c. The name of the standard "System Protection Coordination" is misleading since it only provides guidelines for effective, timely, and accurate information sharing among the entities and does not lay any guidelines for the coordination of the protection systems. d. The term "system configuration change" should be clarified with examples. e. The sections Description of the Current Draft (Page 1 of 11) and Section 3 Purpose (Page 3 of 11) appear to communicate different issues and look inconsistent. The former stresses on "planning time frame" whereas the latter emphasizes on the "information needed". f. Page 1 - "The old requirement R1 has been redeveloped into the new R6 and R7 R5 and R6 which deal with providing Protection System information separately to the Transmission Operator and the Generator Operator. (Incorrect requirement numbers)

Organization	Question 10 Comment
	g. R5 and R6 - Clarify which all entities are included in “Transmission Operator”. Should the ISOs be included along with internal TOPs (control centers) h. Attachment 1 - Step 2 says that “The affected Transmission Owner or Distribution Provider shall review the information provided in step 1 from the Generator Owner (for the purpose of Protection System Coordination) and respond regarding adequacy of the data in the submittal to the Generator Owner within one month of having received the information”. However, if the information received is not deemed to be adequate, there can be several iterations before confirming the adequacy of the received information and this can go well past the “six months” prior to in-service date. There should be a statement that addresses this scenario. i. Attachment 1 - Step 3 - bullet point 2 references: “....the responsible regional reliability organization...”.Is it the Regional Entity (RE) or ISOs? Please clarify. j. For Step 3 in Attachments 1, 2, and 3, revised to add highlighted text to read ‘The Transmission Owner or Distribution Provider and the Generator Owner shall mutually agree on the scope and schedule for implementing the new or proposed relay schemes and setting revisions.’

Response:

a) **The most critical aspect of this Standard is “To ensure that System Protection Coordination is achieved” as stated in the Purpose. Effective and timely sharing of information between entities helps achieve this purpose. Reviewing the shared information (i.e., reviewing device settings) and responding to their adequacy as outlined in the attachments further helps to achieve this purpose. Review of shared information implies that fault and coordination studies will be performed based upon the provided information and the results will be compared and agreed upon between affected entities. This review process ensures System Protection Coordination is achieved, and does impact reliability.**

b) **The drafting team appreciates your comment. The drafting team believes that any information required to be transmitted would not be deemed CIP sensitive.**

c) **The drafting team believes that the title is appropriate. The Standard provides guidance for effective, timely, and accurate information sharing among entities. It is not the intent of the Standard to establish specific criteria for System Protection Coordination such as relay margins or tolerances. There are many references available that describe transmission and generation System Protection Coordination.**

d) **The drafting team has opted not to provide specific examples but more clarification has been added to Requirements R2 and R3 concerning “system configuration change” requiring the Owner to determine if his changes impacts the System Protection Coordination with the interconnected owner.**

e) **The drafting team believes that the Description of Current Draft and the draft Purpose are adequately worded and consistent.**

f) **Thank you for your observations. The errors noted have been corrected.**

g) **The entity registered as the Transmission Operator would be the recipient of the information.**

Organization	Question 10 Comment
h) **The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. If the six months is not enough time for budgeting or construction, then a longer time frame can be negotiated.** i) **This bullet item has been reworded to remove the concerns that you had concerning responsible regional reliability organization.** j) **The drafting team has revised Step 3; however the drafting team believes that if mutual agreement cannot be reached within 60 days, a resolution process (which could include a third party) must be started, and resolution must be reached before Protection System changes can be put in service..**	
Northeast Power Coordinating Council	a. Having timelines as required by the proposed draft of the standard does not enhance reliability of the bulk power system by itself. It is an information sharing mandate that requires entities to share timely and accurate information among themselves. The proposed standard addresses a communications issue not a reliability issue. b. No reference has been made to the CIP Information Sharing standard that addresses how to handle critical infrastructure protection internally and externally. c. The name of the standard “System Protection Coordination” is misleading since it only provides guidelines for effective, timely, and accurate information sharing among the entities and does not lay any guidelines for the coordination of the protection systems. Alternative titles to be considered are "Protection System Information Sharing", or "Protection System Information Coordination". d. The term “system configuration change” should be clarified with examples. e. The sections Description of the Current Draft (Page 1 of 11) and Section 3 Purpose (Page 3 of 11) appear to communicate different issues and look inconsistent. The former stresses on “planning time frame” whereas the latter emphasizes on the “information needed”. f. Page 1 - “The old requirement R1 has been redeveloped into the new R6 and R7 (should be R5 and R6) which deal with providing Protection System information separately to the Transmission Operator and the Generator Operator.” (Incorrect requirement numbers). g. R5 and R6--Should the ISOs be included along with the internal TOPs (control centers)? h. Attachment 1 - Step 2 says that “The affected Transmission Owner or Distribution Provider shall review the information provided in step 1 from the Generator Owner (for the purpose of Protection System Coordination) and respond regarding adequacy of the data in the submittal to the Generator Owner within one month of having received the information”. However, if the information received is not deemed to be adequate, there can be several iterations before confirming the adequacy of the received information and this can go well past the “six months” prior to in-service date. There should be a statement that addresses this scenario. i. Attachment 1 - Step 3 - bullet point 2 references: “....the responsible regional reliability organization...”

Organization	Question 10 Comment
	j. Is it the Regional Entity (RE) or ISOs? Please clarify. k. For Step 3 in Attachments 1, 2, and 3, revised to add highlighted text to read 'The Transmission Owner or Distribution Provider and the Generator Owner shall mutually agree on the scope and schedule for implementing the new or proposed relay schemes and setting revisions.' l. It should be made clear on page 2 (as it is on other standards posted for revision or adoption); Definitions of Terms Used in Standard, that any new or revised terms will become approved when the proposed standard is approved. At that time the terms will be removed from the standard and be added to the Glossary. m. Footnote 1 in Attachments 1, 2, and 3 is not necessary. It is addressed by the Note in the Conditions section of each attachment. n. Requirement R4 assumes the TP or PC will be aware of Protection System Changes resulting from one of the events listed in R2 and R3. However, there is no mechanism described in this standard that ensures the TP or PC would be aware of these, and cause them to request information. The Transmission Owner should be required to inform the TP and/or PC. o. R6 requires that the Generator Operator provide system protection information to the Generator Owner. It would seem to be more beneficial to overall system protection and coordination if the requirements established in R6 apply between the Generator Owner and the Transmission Operator.

Response:

a) **The most critical aspect of this Standard is "To ensure that System Protection Coordination is achieved" as stated in the Purpose. Effective and timely sharing of information between entities helps achieve this purpose. Reviewing the shared information (i.e., reviewing device settings) and responding to their adequacy as outlined in the attachments further helps to achieve this purpose. Review of shared information implies that fault and coordination studies will be performed based upon the provided information and the results will be compared and agreed upon between affected entities. This review process ensures System Protection Coordination is achieved, and does impact reliability.**

b) **The drafting team appreciates your comment. The drafting team believes that any information required to be transmitted would not be deemed CIP sensitive.**

c) **The drafting team believes that the title is appropriate. The Standard provides guidance for effective, timely, and accurate information sharing among entities. It is not the intent of the Standard to establish specific criteria for System Protection Coordination such as relay margins or tolerances. There are many references available that describe transmission and generation System Protection Coordination.**

d) **The drafting team has opted not to provide specific examples but more clarification has been added to Requirements R2 and R3 concerning "system configuration change" requiring the Owner to determine if his changes impacts the System Protection Coordination with the interconnected owner.**

Organization	Question 10 Comment
e) **The drafting team believes that the Description of Current Draft and the draft Purpose are adequately worded and consistent.** f) **Thank you for your observations. The errors noted have been corrected.** g) **The entity registered as the Transmission Operator would be the recipient of the information.** h) **The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. If the 6 months is not enough time for budgeting or construction, then a longer time frame can be negotiated.** i) **This bullet item has been reworded to remove the concerns that you had concerning responsible regional reliability organization.** j) **See response to (i).** k) **The drafting team has revised Step 3; however the drafting team believes that if mutual agreement cannot be reached within 60 days, a resolution process (which could include a third party) must be started, and resolution must be reached before Protection System changes can be put in service.** l) **The drafting team appreciates your comment and the Standard has been modified to include this default language at the top of the page with the proposed definition.** m) **The drafting team appreciates your comment. The drafting team believes, although redundant, that the footnotes in the attachments add clarity.** n) **The drafting team disagrees. The Transmission Planner or Planning Coordinator should be aware of new or modified Protection System schemes due to load flow studies and stability studies run to comply with the TPL Standards.** o) **The drafting team believes R6 is appropriately written with the Generator Owner providing the information to the Generator Operator in order for the Generator Operator to perform its functions.**	
NextEra Energy Resources	a. The terminology under Attachment these attachments are very broad. Under the Conditions section of Attachment 1, the term “impact should be more clearly defined. b. The term “system configuration change” should be clarified with examples. c. The name of the standard “System Protection Coordination” is misleading since it only provides guidelines for effective, timely, and accurate information sharing among the entities and does not lay any guidelines for the coordination of the protection systems... Attachment 1 - Step 2 says that “The affected Transmission Owner or Distribution Provider shall review the information provided in step 1 from the Generator Owner (for the purpose of Protection System Coordination) and respond regarding adequacy of the data in the submittal to the Generator Owner within one month of having received the information”. However, if the information received is not deemed to be adequate, there can be several iterations before confirming the adequacy of the received information and this can go well past the “six months” prior to in-service date. There should be a statement that addresses this scenario.

Organization	Question 10 Comment
Response: **a. The "Conditions" sections of attachments 1, 2 & 3 have been removed from the draft standard. The wording of Requirements R2 & R3 that refers to "impact" has been more modified for clarity. In the revised standard, the phrase, ". . . as determined by the Generator Owner" has been added to R2 and similar language was added to R3 to clarify that the facility owner is the entity that determines whether there is potential impact.** **b. The drafting team has opted not to provide specific examples but more clarification has been added to Requirements R2 and R3 concerning "system configuration change" requiring the Owner to determine if its changes impact System Protection Coordination with the interconnected facility owner.** **c. The drafting team believes that the title is appropriate. The Standard provides guidance for effective, timely, and accurate information sharing among entities. It is not the intent of the Standard to establish specific criteria for System Protection Coordination such as relay margins or tolerances. There are many references available that describe transmission and generation System Protection Coordination.** **d. The drafting team has modified the Attachments so the schedules can change with the mutual agreement of all entities. If the six months is not enough time for budgeting or construction, then a longer time frame can be negotiated.**	
MRO - NERC Standards Review Subcommittee	A. This standard is way too prescriptive. This standard doesn't reflect the NERC initiative to minimize documentation requirements that do not improve system reliability. Protection engineers who already understand the description, purpose, and limitation of relaying already exchange information on a regular basis to ensure coordination. All of PRC-001 could be reduced to a single requirement. Registered entities will exchange system protection data with other impacted neighboring registered entities upon request. For compliance all that a utility would provide is a list of requests and a list of responses. Transmission entities already understand that to avoid problems they must coordinate their protection systems with one another. B. CIP sensitive data should be handled properly. Many times data, such as relay settings, are considered CIP sensitive and could be CIP restricted. At a minimum, exemptions must be placed in the standard to deal with situations when an entity is not CIP compliant. A utility cannot be placed in a situation of choosing between violations. C. The purpose of the standard should be restated slightly to say, "To ensure that System Protection Coordination is achieved with neighboring registered entities and ..."Requirement 1 should not require entities to share their Protective System settings with any interconnected entity, even if the requesting entity requests information about a facility that is not part of their interconnection facilities. MRO NSRS believes that entities should be required to only share information on those facilities that are needed for ensuring that the Protection System are coordinated. There needs to be a clause that states requests for Protection System that are not needed to ensure coordination are not covered by this requirement. D. In attachments, all references to providing stability study results should be deleted. If the standard goes into effect as planned, 3 months after the end of 2010, then an auditor could require that all protection systems be completely modeled everywhere in an entities stability analysis package. There aren't enough relay or stability experts to handle the entire USA

Organization	Question 10 Comment
	suddenly modeling everything - because someone could simply make a request for everything. E. In R2 and R3 the MRO NSRS is concerned that the standard could be interpreted to require every Protection System device in any distribution or generation facility be included, regardless of whether or not it could impact the reliability of the BES. This could effectively require every Protection System an entity owns to meet transmission level requirements. In Articles 2.1, 2.2, 3.1, and 3.2 the following phrase should be added at the end of each sentence "that impacts the reliability of the BES". F. The current language requires both the TO and DP to always complete the actions in attachment 2 / or 3 even if the other is not involved. The reality is that both may not always need to be involved and this requirement will require them to always be involved. Requirements 3.3 and 3.4 should be modified to include a statement impact is to be determined by the responsible entity. Suggested modification: 3.3 Making system configuration changes that are not on the interconnection and may impact, as determined by the TO or DP, System Protection Coordination. 3.4 Making Protection System changes that are not on the interconnection and may impact, as determined by the TO or DP, System Protection Coordination. G. Further concerns with the Attachments 1, 2 and 3. The MRO NSRS is concerned that the procedures outlined in the attachments are overly complex and do not properly represent common practices within the industry. The SDT needs to develop requirements that can capture the overall purpose of the Attachment sections and bring that into the Requirement section of the standard. H. Specific Questions about the Attachment sections: H1. What is a month? (The SDT seems to be assuming that this work will only take place on the 1st day of a month but why should some months be given less time then others?) Our recommendation is to change the month to a 30-day period. H2. When does step 2 start? (Does it start with the first submission of data to the TO or when the TO has acknowledge that the information is sufficient for it to begin the review to determine adequacy?) I. In attachment 1, delete all data references that are not covered by MOD-012 such as generator saturated and unsaturated impedances and zero sequence impedances.

Response:

A. The drafting team appreciates your comments; however, the drafting team believes the details included in this proposed standard will enhance the overall grid reliability. The drafting team believes per FERC Order 693, the included documentation is necessary to demonstrate you are meeting the requirements. The standard requires peer review of new or revised protection settings before they are implemented.

B. The drafting team appreciates your comment. The drafting team believes that any information required to be transmitted would not be deemed CIP sensitive.

C. The drafting team appreciates your comment. The purpose has been changed to 'To ensure that System Protection Coordination between

Organization	Question 10 Comment
interconnected functional entities …' to address your comment. **D. The drafting team believes that stability studies may be needed in order to complete a full analysis. It is noted that such information is only required where it is 'applicable to the proposed change'.** **E. The drafting team has modified the Standard to state "on the interconnected Facilities".** **F. The drafting team has modified the Standard to state "on the interconnected Facilities".** **G. The determination that the items noted in the attachments not be included as 'Requirements' in the Standard were made with the advice of NERC staff.** **H1. The drafting team has modified the Standard to convert "month" into thirty calendar days.** **H2. Step 2 begins when the data identified in Step 1 is received.** **I. The drafting team believes this data may be required to adequately complete the system impedance model.**	
Virginia Electric and Power Company	All time frames should indicate that mutually agreed upon alternative times are acceptable
Response: The drafting team has modified the Standard to address your concerns.	
Western Area Power Administration, Rocky Mountain Region (WACM)	1. Applicability - need to clarify that this standard applies to the Bulk Electric Power System and need to clarify that it applies primarily to interconnections between utilities 2. Under Attachments 1, 2 and 3 recommend adding Step 7 which states something like the following: "Minor adjustments to protection system settings can be expected during the commissioning process. The TO or DP shall submit "as-built" settings or drawing information to the affected TO or DP within one month of commissioning. 3. "Perhaps include some verbiage in the standard that defines the protective relay settings covered by this standard such as protective trips and auto-reclosing but not monitoring, event recording, SOE, display, I/O layout or Control or SCADA Open and Close functions.
Response: 1. The Purpose has been modified to include 'between interconnected functional entities.' **2. The drafting team has modified the Standard to state: 7. Adjustments to Protection System settings that are agreed upon by the interconnected Facility owners during the commissioning process shall be documented to the interconnected functional entities within 7 calendar days after the in-service date.** **3. The items you list that do not affect System Protection Coordination are not required to be provided.**	

Organization	Question 10 Comment
NERC - Director of Event Analysis and Information Exchange	As written, PRC-001-2 does not require coordination between existing generation and transmission systems except on an “upon request” basis or if changes are made to the generator or transmission protection system. This is not acceptable from a reliability standpoint. The stated ability to request a coordination review of an existing unit, and the requirement to review coordination whenever the generation or transmission protection systems are modified, and for all new units are good requirements. However, as written, they “grandfather” the majority of the generation fleet. Of the 43 protection Misoperations found to be causal or contributory to significant system disturbances over the last 3 years, 12 of those were determined by the NERC Event Analysis program to be caused by miscoordination of generation and transmission protection systems. Under the proposed draft of PRC-001-2, none of those would be required to be coordinated. Recognizing that a review of coordination of all existing generator protection with transmission protection systems would be a monumental task, a significant amount of time (3-5 years) would be required to perform a complete review and must be factored into the Implementation Plan for the standard. This is especially true in light of the myriad of other protection reviews being required by various other protection system standards. A one-time review of all units, similar to the protection system loadability review conducted after the 2003 blackout, should be included in the Implementation Plan with sufficient time to accomplish the task.
Response: The drafting team discussed this issue and believes that the requirement to provide requested data allows entities to facilitate coordination review on any interconnections that they believe need review and lays out a clear process for new facilities. It is noted that coordination issues that result in Misoperations will be investigated and appropriate Corrective Action Plans created to address per PRC-004.	
Duke Energy	1. Attachments 1, 2 and 3, under Conditions, the second bullet identifies: “A system configuration change or Protection System change that is not on the interconnection but may impact System Protection Coordination on the interconnection.” Additional clarification should be provided regarding what is included in the scope of “system configuration change”. Would this include balance-of-plant changes that could take a generating unit off-line due to reduced transient voltage during a fault or excitation system changes that would impact plant stability and the required protection system settings? Changes like these could impact system protection design requirements and would not necessarily be considered a “system configuration change”. 2. Enhancement to the supplement document is needed to clarify if protection systems on auxiliary plant equipment that indirectly result in the loss of the generation are included within the scope of PRC-001-2 compliance. Example 1, would undervoltage protective trip elements on auxiliary motor loads be included within the scope of PRC-001-2, if trip of those motors results in a subsequent, expected control trip of the generation? Assume the undervoltage elements on the auxiliary motors trip for voltage sag associated with a non-intertie line fault cleared by Zone 2 line protection. Example 2, assume loss of the same motors in example 1 but due to dropout of contactors from the voltage sag. Would the line protection or contactor circuit design be subject to PRC-001-2 compliance?
Response: 1. The drafting team thanks you for your comments. The intent of the second bullet is to account for system changes that would impact System Protection Coordination as defined in the standard. Examples would be the addition of a fault source close to, but not immediately	

<table>
<tr><th>Organization</th><th>Question 10 Comment</th></tr>
<tr><td colspan="2">associated with the interconnection or reconfiguration of transmission line configurations immediately out of the tie station.

2. The standard indicates that only those protective devices that trip the generator need to be reviewed for coordination. Auxiliary equipment trips that subsequently cause the generator to trip are not currently included in the standard’s scope.</td></tr>
<tr><td>ITC Holdings</td><td>1. Our company requires Synchronized End to End testing on new pilot schemes. Our interconnected utilities do not all require this. There is nothing in the standard about coordination of commissioning or testing relay systems.

2. The Standard Reference document lists the relay elements that need to be coordinated with the connected entity. This list includes many of the protective elements that trip either the generator of the transmission segment. There is more needed here. We need to know information about which elements on the transmission system need to be coordinated with which element on the generator or visa versa.

3. The wording in R1 indicates that an entity must provide its Protection System settings and scheme types within one month when requested..... This is not enough information to coordinate relays. Since the attachments indicate the detailed information that is required by the connected entity, either this should be referred to or the statement should be more inclusive, such as “the necessary Protection System information”.

4. In Attachment 3 we do not see the relevance of the RRO off-nominal frequency plan being part of the required data. Please explain.</td></tr>
<tr><td colspan="2">Response:

1. The drafting team believes that commissioning requirements are outside the scope of this standard.

2. The drafting team believes that the amount of detail you suggest is not appropriate within the standard. There are many references available that describe transmission and generation System Protection Coordination.

3. Requirement R1 is associated with existing power system elements that have already been coordinated. Any new request that pertains to this requirement would normally be a result of the need to update files, periodic review of the coordination, or to investigate an apparent Misoperation.

4. The drafting team thanks you for your comment and has removed the off-nominal frequency plan data submittal from Attachment 3.</td></tr>
<tr><td>Georgia Transmission Corporation</td><td>1. Consideration should be given not to apply standard when the GO, TO, and Transmission Planner is the same company. Should NERC be driving internal processes?

2. "Limitation" of systems could be defined clearer or examples given. Please clarify when talking about new systems or existing systems in the document. Please clarify impact on the interconnection or give examples.</td></tr>
<tr><td colspan="2">Response:</td></tr>
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Organization	Question 10 Comment
1. The drafting team recognizes that some entities are registered as both a Transmission Owner and as a Generator Owner. That dual registration may be supported by different engineering staffs or by the same group of engineers. The drafting team believes that the requirements in PRC-001-2 apply equally to generator/transmission interconnections regardless of the umbrella of ownership or organizational structure. Even if the same engineer works on the Protection Systems on each side of the interconnection there must be documentation showing that the coordination issues have been addressed in the time frames detailed in the standard. **2. In this context "limitations" means the characteristics of a Protection System that might impact operation. Examples of this could be the possibility of phase overcurrent or phase impedance relays to sense and operate for high loading conditions, the attenuation of power line carrier signals when ice accumulates on transmission lines, or the tendency of the system to distribute current differently to relays when certain power system elements are out of service. This knowledge can help the Transmission Operator or Generator Operator recognize the causes of unusual Protection System operations or in unusual operating conditions In reference to your "impact on the interconnection," the intent is to account for system changes that would impact System Protection Coordination; such as the addition of a fault source close to but not immediately associated with the interconnection or reconfiguration of transmission line configurations immediately out of the tie station.**	
RelaibilityFirst Corporation	In Attachment 1- Suggest moving the "Generator off-nominal frequency and voltage operating limits" to the section above and make it part of the minimum requirements.
Response: The drafting team thanks you for your comment but believes the way the standard is written allows for the flexibility of requesting the information as needed.	
Luminant Power	In NERC document PRC-001-2 System Protection Coordination Supplementary Reference, Luminant recommends page 3 should include the same data exchange on Communication-aided schemes shown on the bottom of page 5.
Response: The drafting team thanks you for your comment and has modified the Supplementary Reference document by adding the same data exchange on Communication-aided schemes to page 3 - *Transmission and Distribution Protection Devices or Elements that May Require Coordination with Generator Protective Devices in Requirement R3*.	
PSEG	1. In R1, the list of example scheme types seems to be somewhat limited, is this by design, or is NERC primarily focused on certain relay functions typically used with generation? 2. In the reference to Attachment 2, the bullet stating that "the TO shall, as a minimum, provide Drawing(s) showing the relay(s) and its (their) ac sources(s)." should be placed in the next set of bullets. These drawings should only be furnished upon request. R5.1 needs more clarification. What is the format for this data? 3. Is the TOP expecting a write-up on each interconnection line? Are they expecting a write-up of how all of the specific relay schemes work? 4. What does "limitations" mean?

<table>
<tr><th>Organization</th><th>Question 10 Comment</th></tr>
<tr><td></td><td>5. The TO can tell the TOP what schemes are employed on their system. However, the onus should be on the TOP to understand the basics of how the schemes work and what the purpose of the schemes are. In any case, the TOP needs to let the TO’s know how the “operating decisions” might be affected by the specific relay scheme. This will help the TO supply the correct data to the TOP.</td></tr>
<tr><td colspan="2">Response:
1. The scheme types listed in Requirement R1 are only examples to clarify what is meant by “scheme types” and are not intended to imply NERC’s primary focus.
2. The drafting team thanks you for your comment but believes that the drawings are important to the ability to perform System Protection Coordination. For example, the next item in the list is the “Applied instrument transformer(s) and configuration(s),” which would provide little information without the drawings.
The drafting team believes that each individual entity is best able to determine the appropriate format for providing the required information.
3. The standard states that the “general description, purpose and limitations of each existing type of transmission Protection System scheme applied to its system” need to be provided to the Transmission Operator. The drafting team believes this indicates that information on the types of schemes applied is required and not specific information on each individual element’s Protection System.
4 In this context “limitations” means the characteristics of a Protection System that might impact operation. Examples of this could be the possibility of phase overcurrent or phase impedance relays to sense and operate for high loading conditions, the attenuation of power line carrier signals when ice accumulates on transmission lines, or the tendency of the system to distribute current differently to relays when certain power system elements are out of service. This knowledge can help the Transmission Operator or Generator Operator recognize the causes of unusual Protection System operations or in unusual operating conditions.
5. The drafting team thanks you for your comment.</td></tr>
<tr><td>Bonneville Power Administration</td><td>no additional comments</td></tr>
<tr><td>Electric Market Policy</td><td>No additional comments.</td></tr>
<tr><td>Entergy Services</td><td>None.</td></tr>
<tr><td>PNGC- Cowlitz PUD - Central Lincoln PUD group</td><td>None.</td></tr>
</table>

Organization	Question 10 Comment
E.ON U.S.	1. On R6, could a phrase be added at the beginning of the requirement that states something such as "Unless the Generator Owner and the Generator Operator are within the same Company..." in order to exempt having to create documentation/evidence for utilities where the Generator Owner/Operator are the same responsible personnel. 2. On Attachment 1, Step 1, regarding what to provide when requested, the phrase "as available" should be added. Some of this data is unavailable for older equipment. It is unreasonable to penalize or identify a company as being in violation because their plant includes older equipment for which this type of information is unavailable. 3. No limitation on size or voltage level has been established for this standard, e.g., > 100 KV. 4. E.ON U.S. believes that R2.3 & 2.4 and R3.3 & 3.4 seem very broad in that any changes to system protection or system configuration that could affect system protection coordination are included 5. The footnote saying "The time restrictions do not apply to changes that are a reaction to failures of components in Protection Systems if the replacement of components is with functional equivalents." should be softened even more to include situations where a component may not have failed (e.g. failure is imminent or component is suspect) and permit replacement with components that meet or exceed functional equivalents. The same comment applies to the "NOTE:" under "Conditions" in Attachment 1, 2 and 3.
Response: **1. The drafting team believes Requirement R6 is appropriate regardless of a company's organizational structure.** **2. The drafting team believes that the information in step 1 of Attachment 1 is necessary and should be available.** **3. The standard applies to facilities owned by the interconnected functional entities listed; Transmission Owners, Generator Owners, and Distribution Providers that own transmission Protection Systems. The standard does not specify a voltage level.** **4. The drafting team agrees. PRC-001-2 applies to any changes that affect System Protection Coordination with interconnected entities and the standard has been modified for clarity.** **5. The footnote applies to Protection System failures. If the Protection System has not failed then the steps in the Attachments should be followed for replacement or upgrades. Note that the standard was revised to provide greater latitude on the time frames – and now includes the phrase, "or according to an agreed upon schedule."**	
Exelon	R1 doesn't address coordination of existing generators, it should require that existing generators be checked to assure coordination is sufficient based on learnings from system events and the 2003 Blackout as reflected in the paper written by the NERC SPCS (System Protection and Control Subcommittee), Power Plant and Transmission System Coordination once this paper is approved by the NERC Planning Committee. These learnings may not be reflected in existing designs.

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	Once existing generation is checked within an appropriate timeframe of a number of years (timeframe should reflect consideration based on all the other revised NERC standards that are being issued to the industry at this time), the requirement could be changed back to as it is currently written.
Response: Requirement R1 provides the opportunity for either entity that has questions related to existing units to request the needed data to ensure adequate protection studies can be done where previous coordination documentation does not exist.	
Northeast Utilities	R6 requires that the Generator Operator shall provide system protection information to the Generator Owner. It would seem to be more beneficial to overall system protection and coordination if the requirements established in R6 apply between the Generator Owner and the Transmission Operator.
Response: The drafting team believes Requirement R6 is appropriately written with the Generator Owner providing the information to the Generator Operator in order for the Generator Operator to perform its functions.	
Puget Sound Energy	1. Regarding to the specific information that must be provided as a minimum under step 1 of Attachment 1, 2, and 3, generally a full set of AC & DC schematics/drawings are not available 6 months in advance of the in service date. Historically, only a description of the scheme and the relay setting sheets or perhaps a setting file has been available. We are unclear what level of drawing is expected at this point in the process and whether a meter-relay one-line diagram would suffice. 2. R7 is mentioned in the background discussion at the beginning of this comment form which doesn't appear in the draft revision.
Response: 1. The intent is that the needed information be provided; however, the format of the data is determined by the parties. It is recognized that the requirements in this standard may require changes in present engineering and setting timetables used by some entities. **2. This was a typo and has been corrected to Requirement R6.**	
Xcel Energy	1. Section A-Introduction a) Do the PRC standards inherently apply to BES? We failed to see anything in the standard that clearly states that it applies only to BES. Please clarify. b) Does this standard apply to internal system coordination as well as interconnection coordination? System Protection Coordination seems to imply coordination of the entire transmission system internally as well as externally. If this standard only applies to coordination of interconnections, then it should be made more clear and its title should be changed to

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	"Interconnection Protection Coordination". 2. Section B-RequirementsR1. a) We feel that system modeling information should also be required to be provided, in addition to settings and scheme types, within one month of request. b) It appears that the intent of this requirement is to get Transmission Owners, Distribution Providers and Generator Owners to check the existing coordination of their facilities with one another to ensure that adequate coordination already exists. The intent of this requirement needs to be clarified. c) Please clarify if this requirement will have to be verified on a periodic basis. 3. R2.3 Regarding "Making any system configuration change..." does this apply to permanent changes only? What if a temporary system configuration change was made? 4. R2.4 Regarding "Making any Protection System change..." does this apply to permanent changes only? What if a temporary Protection System change was made? 5. R3.3 a) Regarding "Making system configuration changes..." does this apply to permanent changes only? What if a temporary system configuration change was made? b) This needs to be clarified. Some examples of what constitutes a system configuration change that will impact System Protection Coordination in an appendix or additional attachment would be beneficial. 6. R3.4 a) Regarding "Making Protection System changes..." does this apply to permanent changes only? What if a temporary Protection System change was made? b) This needs to be clarified. What types of internal Protection System changes need to be considered? Does every internal Protection System change need to be checked to see if it impacts System Protection Coordination with a neighboring entity? Examples in an appendix or attachment would be useful. 7. R5. This requirement appears to be about providing information on Protection System schemes to operators to promote informed operating decisions. However, parts 5.1 and 5.2, as written, appear to require information only for each type of scheme without necessarily revealing where such schemes are applied. We doubt that was the intent of the drafting team.

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	Please clarify the intent of the requirement, and make any necessary text modifications. 8. R6. This requirement appears to be about providing information on Protection System schemes to operators to promote informed operating decisions. However, parts 6.1 and 6.2, as written, appear to require information only for each type of scheme without necessarily revealing where such schemes are applied. We doubt that was the intent of the drafting team. Please clarify the intent of the requirement, and make any necessary text modifications. 9. Attachments 1, 2 and 3 These attachments would be more clear if presented as process maps. The steps are well defined and appropriately organized, but not every condition will start at step 1. For example, if new Protection System settings need to be implemented that impact coordination of the interconnection, the process should start at step 4, not step 1.

Response:

1. a: The drafting team considered the use of the Bulk Electric System (BES) in the standard but the BES is not uniformly defined by the Regional Entities. The use of the registered entities: Transmission Owners, Generator Owners and Distribution Providers that own transmission Protection Systems was considered the appropriate solution since these terms are universally accepted NERC defined terms and include the entities that are responsible for maintaining a reliable electric system.

1. b: The standard does apply to interconnections only, and the Purpose statement has been modified to reflect your comment. The purpose now includes the phrase, "between interconnected functional entities."

2. a. The drafting team believes that existing system modeling data exchange is currently addressed in the NERC MOD Reliability Standards.

2. b. The intent of Requirement R1 is to permit the requesting entity to verify that its information regarding the interconnected Protection Systems is up-to-date and coordinated.

2. c. The drafting team did not intend that periodic re-verification is required.

3. The drafting team intends Requirement R2, Part 2.3 to apply to planned system configuration changes that impact the System Protection Coordination. Temporary changes in the planning timeframe are not excluded. Requirements that deal with the operating timeframe are addressed in the operating standards.

4. The drafting team intends Requirement R2, Part 2.4 to apply to planned Protection System changes that impact the System Protection Coordination. Temporary changes in the planning timeframe are not excluded. Requirements that deal with the operating timeframe are addressed in the operating standards.

5. a. The drafting team intends Requirement R3, Part 3.3 to apply to planned system configuration changes that impact the System Protection Coordination. Temporary changes in the planning timeframe are not excluded. Requirements that deal with the operating timeframe are addressed in

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the operating standards **5. b. The drafting team has opted not to provide specific examples but more clarification has been added to Requirements R2 and R3 concerning "system configuration change" requiring the Owner to determine if its changes impact the System Protection Coordination with the interconnected Facility owner.** **6. a. The drafting team intends Requirement R3, Part 3.4 to apply to planned Protection System changes that impact the System Protection Coordination. Temporary changes in the planning timeframe are not excluded. Requirements that deal with the operating timeframe are addressed in the operating standards.** **6.b The drafting team has opted not to provide specific examples but more clarification has been added to Requirements R2 and R3 concerning Protection System changes requiring the Owner to determine if its changes impact the System Protection Coordination with the interconnected Facility owner.** **7. The intention of Requirement R5, Part 5.1 was to provide the Transmission Operator with information on existing schemes applied on a general basis. Therefore, there could be a single description of an entity's DCB scheme, Permissive Overreaching Transfer Trip scheme, etc. Requirement R5, Part 5.2 does the same action for new schemes. The intention of Requirement R5, Part 5.3 is to provide more specific transmission Protection System information to the Transmission Operator as requested.** **8. The intention of Requirement R6, Part 6.1 was to provide the Generator Operator with information on existing schemes applied on a general basis. Requirement R6, Part 6.2 does the same action for new schemes. The intention of Requirement R6, Part 6.3 is to provide more specific generation Protection System information to the Generator Operator as requested.** **9. The drafting team thanks you for your comment concerning process maps. The drafting team has modified the attachments to allow greater flexibility between the interconnected owners, and does not believe that process maps are required.**	
Pepco Holdings, Inc - Affiliates (PH)	See additional comments on specific sections as listed below: 1. Section 4.2 - The definition of facilities should be re-written to qualify the scope of this document to be applicable to BES facilities. Suggest wording such as "4.2 Facilities: All generation and transmission Protective Systems installed on the Bulk Electric System owned by...." 2. Section R1 - The present wording is too vague. R1 requires supplying data "to other owners of Facilities to which they are interconnected". Does this mean supplying data for facilities only associated with the direct interconnection, or facilities in the vicinity of the direct interconnection (i.e., lines and equipment originating on the interconnection bus), or anywhere on the entire system? Is a TO responsible for providing data to another TO, or GO, on facilities numerous busses away from the direct interconnection within one month of request? Further clarification is required. 3. Sections R3.1 & R3.2 - Although the introductory paragraph to R3 mentions in accordance with Attachment 2 and/or 3, the wording of R3.1 & R3.2 should be consistent with that of the attachment. For example, Attachment 2 qualifies this as "Any new or revised Protective System that is interconnected with a Generation Owner's facilities." This language

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	in the Attachment appears to bind the scope of the requirement to those Protection Systems associated with the direct interconnection. 4. Sections R3.3 & R3.4 - The phrase “and may impact” is nebulous and requires definition to be auditable / enforceable. No requirement should use this term. Who determines if the change may impact System Protection Coordination? What criteria are to be used to make that determination? How would a registered entity document compliance? Further clarification and a list of examples of what would, or would not, be in scope should be provided. 5. Section R4 - As presently worded, this requirement is very open ended and could result in a Transmission Planner or Planning Coordinator requesting detailed technical data on every Protection System on the Transmission Owner’s system within one month. The proposed time frame for a request of this magnitude would seem unreasonable. R4 should be limited to requests for data for new or functionally modified Protective Systems. If the intent was to gather data on all Protective Systems on the system then it should be re-written similar to R5.1 with a much longer timeframe (say 12 months) to respond to such requests. 6. Section R5.1 - This section requires the Transmission Owner or Distribution Provider to provide to its Transmission Operator the general descriptions, purposes and limitations of the existing types of transmission Protection System schemes applied on its system within 6 months following the effective date of the Standard. This requirement is very vague as to what specific data is required. One might interpret this to mean providing information such as: Line xyz is protected by a primary POTT pilot scheme and a 3 zone distance back-up scheme, with an X MVA steady state relay load limit. Someone else might interpret this to mean having to supply much more detailed scheme descriptions, including relay communication channel descriptions, zone distance relay reaches, clearing times and load limits for each protective zone or element, and detailed instructions as to what action to take for a failure of each protective system component. Additional clarification or specific examples of what is expected should be provided. Also, due to the uncertainty surrounding the extent of the data required to be supplied, the present 6 month time frame should be extended to at least 12 months. This time frame could be refined on subsequent drafts once the scope of this data submittal is better defined. 7. Section R5.2 - Same general comment as R5.1. Additional clarification or specific examples of what is expected should be provided. The term “general description, purpose, and limitations” is too vague and subject to multiple interpretations. 8. Attachments - In addition to the remarks previously provided regarding timeframes, dispute resolution, and the phase “and may impact”, the following comments are offered: In all three attachments Steps 2 & 5 require one party to review data submitted by the other party “(for the purpose of Protection System Coordination) and respond regarding the adequacy of the data submittal within one month of having received the information.” It is unclear as to what compliance responsibilities the reviewing party has regarding “coordination of protective systems” during this review process. For instance, suppose a Generator Owner (GO) supplies his interconnected Transmission Owner (TO) with relay drawings and settings. The TO would review the GO data to ensure that the Protective Systems on the TO system would “coordinate” with the GO Protective System. In other words, the TO would review “faults” on the GO

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	facilities and ensure that the GO Protective Systems would operate prior to any Transmission Protective Systems Operating. The TO should not be responsible, in terms of compliance, for reviewing, or commenting on, the adequacy of the GO Protective System to adequately protect GO facilities. That is the responsibility of the GO. Similarly, while the TO must supply the GO with data on the Protective Systems installed on its transmission system, the TO should not be responsible, in terms of compliance, for reviewing the GO protective System to ensure it “coordinates”, or operates prior to the TO Protective Systems. From a compliance perspective that should be the GO responsibility. These compliance responsibilities should be clearly defined in the standard. 9. Attachments 2 & 3 require the Transmission Owner, upon request, to supply the Regional Reliability Organization’s off-nominal frequency plan to interconnected entities. GO compliance with RRO off-nominal frequency requirements should be between the GO and RRO. The TO should not be brought into that compliance process by requiring them to supply RRO requirements to the GO. Similarly, these attachments require the TO, upon request, to provide results of stability studies to interconnected entities. Stability studies are conducted by the Transmission Planner or Planning Coordinator, not the Transmission Owner. As such, it should be the responsibility of the Transmission Planner, or Planning Coordinator, not the Transmission Owner to provide this information, and to provide recommendations regarding mitigation recommendations (i.e., infrastructure upgrades, modifications to Protective System clearing times, installation of out-of-step tripping devices, etc.) Section 4.1 should therefore be revised to include the responsibility of the Transmission Planners and/or Planning Coordinators. Supplementary Reference Document - See comments concerning voltage, frequency, and reclosing elements addressed in the response to Question #2.

Response:

1. The drafting team thanks you for your comment. The drafting team considered the use of the Bulk Electric System (BES) in the standard but the BES is not uniformly defined by the Regional Entities. The use of the registered entities: Transmission Owners, Generator Owners and Distribution Providers that own transmission Protection Systems was considered the appropriate solution since these terms are universally accepted NERC defined terms and include the entities that are responsible for maintaining a reliable electric system.

2. The drafting team has modified Requirement R1 to clarify that it applies only to direct interconnection Protection System settings and scheme types.

3. The drafting team thanks you for your comment and has modified Requirement R3, Parts 3.1 and 3.2 by adding the phrase, “on the interconnected Facilities”.

4. The drafting team have modified Requirement 3, Parts 3.3 and 3.4 to state that the Transmission Owner or Distribution Provider determines whether or not a change that is not on the interconnection impacts the System Protection Coordination.

5. The drafting team has modified the Requirement to allow more flexibility by stating that the information can be provided …“according to an agreed upon schedule.”

6. The intention of Requirement R5, Part 5.1 was to provide the Transmission Operator with information on existing schemes applied on a general

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basis. Therefore, there could be a single description of an entities' DCB scheme, Permissive Overreaching Transfer Trip scheme, etc. Since the detailed information is not required to meet Requirement R5, Part 5.1, the drafting team believes that 6 months is sufficient. **7. The intention of Requirement R5, Part 5.2 was to provide the Transmission Operator with general information as in Requirement R5, Part 5.1 on new schemes applied.** **8. The drafting team agrees that each entity is responsible for its own protection as far as insuring that it adequately protects the equipment it is intended to protect. The drafting team has modified the requirements and the attachments to insure that all entities will be held responsible for their assigned actions in the requirements and attachments.** **9. The drafting team thanks you for your comments. Attachments 2 & 3 have been revised to remove information on off-nominal frequency plans, but the drafting team believes stability study results are necessary because of maximum clearing time requirements. The drafting team disagrees that Transmission Planners and Planning Coordinators should be added to the Applicability section. The drafting team thanks you for your comments regarding Question 2; please see our previous response above.**	
NV Energy	1. The present PRC-001-1 specifically limits its purpose to the relationship among applicable entities, Purpose: To ensure system protection is coordinated among operating entities. The proposed new PRC-001-2 purpose is significantly expanded as follows: Purpose: To ensure that System Protection Coordination is achieved and to ensure that real-time operating personnel have the information needed to react to the operations of Protection Systems and Transmission Planners have Protection System information to perform planning functions. The proposed standard really includes three separate purposes. It may be useful for the intent of these comments to highlight these purposes by re-formatting: Purpose: To ensure that3.1 System Protection Coordination is achieved and3.2 Real-time operating personnel have the information needed to react to the operations of Protection Systems and3.3 Transmission Planners have Protection System information to perform planning functions. 2. Neither the new first purpose in PRC-001-2 nor the new definition of System Protection Coordination recognizes the relationship among applicable entities. This may reasonably lead to the conclusion that the standard is intended to apply throughout the Bulk Electric System, not just to interconnections among entities. It would then also apply to Protection System Coordination within each entity. This may be a useful purpose, if that is the intent, but the remainder of the PRC-001-2 draft, where is does address System Protection Coordination (R1 - R4), turns the focus back to the relationships among the applicable owners/providers. 3. So, do Requirements R1 through R4 address the first purpose of this revised standard? 4. Is the first purpose of the revised standard overstated? 5. Requirement R1.Three communications-aided scheme type examples are listed parenthetically in such a way as to imply a complete list. The PRC-001-2 Standard Reference provides a much more extensive list of both non-

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	communication-aided and communication-aided scheme types. Even this list may not be exhaustive. Suggest removing the "or" and adding "et al" or "etc" at the end of the parenthetical list to clarify that the listed schemes do not include all possible scheme types.
Response: **1. The drafting team thanks you for your comment but does not believe this is necessary.** **2. The drafting team thanks you for your comment and has modified the Purpose statement by adding the phrase, ". . . between interconnected functional entities."** **3. Requirements R1 through R3 address System Protection Coordination and Requirement R4 addresses the needs of Transmission Planners having Protection System information to perform planning functions.** **4. The drafting team thanks you for your comment and has modified the Purpose statement to address your concern – see response to comment 2 above.** **5. The drafting team thanks you for your comment. The drafting team used the Latin abbreviation 'e.g.' because this list of scheme types is not intended to be comprehensive or exhaustive.**	
American Transmission Company	1. The purpose of the standard should be restated slightly to say, "To ensure that System Protection Coordination is achieved with neighboring entities and ..." 2. Requirement 1 requires entities to share their Protective System settings with any interconnected entity even if the requesting entity request information about a facility that is not part of their interconnection facilities. ATC believes that entities should be required to only share information on those facilities that are needed for ensuring that the Protection System are coordinated. Their needs to be a clause that states requests for Protection System that are not needed to ensure coordination are not covered by this requirement. 3. Requirement 2 applies to the Generator Owner but has obligations that apply to both the Transmission Owner and Distribution Provider. (See Attachment 1) 4. Requirement 3 should be broken into two requirements. 1) One requirement that focuses on the TO and 2) one requirement that focuses on the DP. The current language requires both the TO and DP to always complete the actions in attachment 2 / or 3 even if the other is not involved. The reality is that both may not always need to be involved and this requirement will require them to always be involved. 5. Requirements 3.3 and 3.4 should be modified to include a statement impact is to be determined by the responsible entity. Suggested modification: 3.3 Making system configuration changes that are not on the interconnection and may impact, as determined by the TO or DP, System Protection Coordination. 3.4 Making Protection System changes that are not on the interconnection and may impact, as determined by the TO or DP, System Protection Coordination.

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	6. Concerns with the Attachments 1, 2 and 3 ATC is concerned that the procedures outlined in the attachments are overly complex and do not properly represent common practices within the industry. The SDT needs to develop requirements that can capture the overall purpose of the Attachment sections and bring that into the Requirement section of the standard. Specific Questions about the Attachment sections: What is a month? (The SDT seems to be assuming that this work will only take place on the 1st day of a month but why should some months be given less time then others?) When does step 2 start? (Does it start with the first submission of data to the TO or when the TO has acknowledge that the information is sufficient for it to begin the review to determine adequacy?) ATC believe that the requirements should identify the what and not specify the how. Our reading of the time frames (Attachments 1, 2 and 3) is such that the deadlines cannot be negotiated. Did the team anticipate that entities will be allowed to negotiate the deadlines? In addition, ATC is concerned that a major project could cause an entity to be out of compliance with the specified deadline. 7. What types of projects did the team study to determine the time period? 8. Did the team perform any field study or data collection efforts to support the specified deadlines? Ultimately we believe that the team should delete the Attachments and place any necessary information into the requirements. 9. ATC believes that the applicability of this standard is for BES facilities. Does the team agree with our position? If not could the team identify facilities that are not part of the BES but would be required to comply with the standard? Our concern is that this standard could be interpreted incorrectly to apply to auxiliary power feeds at power plants. Is the intent that some will and some will not? If so, how are entities determine those interconnection points? 10. Last ATC believes that the team needs to clarify what is meant by the word “limitations” contained in R5 and R6. ATC believes that the best approach is to delete the word from those requirements. An alternate suggestion would be: Include the phrase “limitations as determined by the entity”

Response:

1. The drafting team has modified the Purpose based on the industry comments – the following phrase was added for clarity: “. . .between interconnected functional entities . . .”

2. Requirement R1 applies only to the Protection Systems applied directly on the interconnection. The drafting team has made modifications for clarification – the revised standard includes the qualification: “. . . to interconnected Facility owners . . .”

3. Thank you for your comments. The drafting team has made changes to Requirements R2 and R3 and the Attachments so that Requirement R2 solely applies to the Generator Owner.

4. Requirement R3 only applies to Transmission Owners and Distribution Providers that own transmission Protection Systems. There does not appear to be any reason to split this requirement based on applicable entities.

5. The drafting team appreciates your comment and the standard has been modified to clarify that impact is to be determined by the facility owner.

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6. The drafting team believes that all the steps in the Attachments are needed. Step 2 in the Attachments starts when the data identified in step 1 is received. The drafting team has made a number of changes to the Attachments. For all but the six month reference, the monthly references have been converted to the appropriate number of days. The standard has been modified to clearly state that the time frames in Attachments can change with the mutual agreement of all entities. **7. No specific projects were studied.** **8. No studies were performed. The format of the requirements and the attachments were developed with the advisement of NERC staff. Because the requirements reference the attachments the attachments become a formal extension of the requirements.** **9. The drafting team does not believe that the standard is only applicable to BES facilities. An example of facilities that are not part of the BES but are applicable are generators 20 MW and greater that are connected below 100 kV. In general, the standard does not apply to auxiliary power systems.** **10. In this context "limitations" means the characteristics of a Protection System that might impact operation. Examples of this could be the possibility of phase overcurrent or phase impedance relays to sense and operate for high loading conditions, the attenuation of power line carrier signals when ice accumulates on transmission lines, or the tendency of the system to distribute current differently to relays when certain power system elements are out of service. This knowledge can help the Transmission Operator or Generator Operator recognize the causes of unusual Protection System operations or in unusual operating conditions.**	
Flathead Electric Co-op	The reasoning behind the significant expansion of the scope of a standard and the actual reliability benefit to the BES should be well-justified. Smaller DP entities are already sufficiently required to coordinate protection systems with their TO/TOP/BA and others in existing standards.
Response: The draft standard has three main focal points: 1) to coordinate Protection Systems, 2) to ensure that real-time operating personnel have the Protection System information they need to make good operating decisions regarding protection and 3) to provide Transmission Planners the Protection System information needed to perform planning studies. The standard provides the steps needed to coordinate the design as well as the settings to ensure proper operations. It has been stated many times that a contributing cause of many wide area disturbances is the Misoperation of Protection Systems. Therefore; the drafting team believes that system performance is greatly impacted by System Protection performance. This standard does not apply to Distribution Providers unless they own transmission Protection Systems.	
Oncor Electric Delivery	The Standard Drafting team did an exceptional job in following the recommendations provided in the SAR. The Drafting team should be commended for removing those requirements contained in PRC-001-1 which apply to operating issues and transferring them to the appropriate standards that deal with issues in the operating time frame. By clearly defining System Protection Coordination for this standard, the Drafting team delineates that PRC-001-2 is to only target coordination of fault clearing. Coordination of other protective systems should be left in the standards where they currently reside. Other PRC standards and TPL standards have been, are being, or should be developed to address Protection System responses to disturbances on the BES other than fault clearing. For example, PRC-006 and PRC-010 were developed to expressly deal with frequency and voltage disturbances by defining the requirements for Under Frequency Load Shedding and Undervoltage Load Shedding. To ensure that generators will not trip off line during voltage and frequency excursions as a

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	result of improper coordination between generator protective relays and voltage regulator controls PRC-024 is being developed. PRC-023 was developed to prevent protective relays from limiting transmission loadability. The Transmission Planning Standards TPL-001, TPL-002, TPL-003 and TPL-004 were developed to ensure that reliable systems are developed that meet specified performance requirements such as stable power swings. It is our opinion that the Standard Drafting team by clearly setting down that PRC-001-2 should only be intended for coordination of fault clearing precludes including relay loadability for generator Protection Systems in PRC-001. NERC has clearly demonstrated that new PRC standards can and should be developed using the NERC Standard Development Process when an issue such as relay loadability for Generator Owners comes along. The Standard Drafting team of PRC-001-2 should be commended for recognizing this fact and making their proposed standard extremely clear that it is not a catch all standard for handling coordination for all types of system disturbances.
Response: The drafting team appreciates your support.	
US Bureau of Reclamation	This document is the first which ensured coordination between the Generator, Transmission, and Distributor functions. The SDT should be complimented for that effort. There are however, a few areas that could use improvement not identified in the previous questions. 1. It is not clear why the Generator Owner should provide Transmission line impedances (positive and zero sequence) to the Transmission Owner. These should be known by the owner. It would be appropriate if the GO needed to demonstrate that the correct line impedances were used on the protection coordination. Since the primary concern is the coordination of "...Only those protective devices that trip the generator need to be reviewed for coordination..." why would any device that trips the generator be included in the list to the TO. This requirement should be clarified as components listed in the supplemental document. 2. The requirements use the tern Protection System. While at least one RRO has provided clarity in what elements that includes, this draft needs to remain consistent in the use of the concept. By referring to a subset of relays in the reference document and using the term Protection System, an apparent conflict or pseudo definition has been created. It would be better to use a lower case term and let the reference be to the subset of relays. 3. The Standard relies on the definition "System Protection Coordination - the design and setting of Protection Systems so that they remove the minimum number of power system elements from service when clearing faults while meeting the performance requirements specified within the NERC Transmission Planning (TPL) reliability standards." These requirements should be clearly articulated in order to develop the measures. The terminology is not as clear as it could be, while the reference documents provide specifics to fulfill requirements, the standard does not. 4. Consider R1. The phrase "Each Transmission Owner, Distribution Provider and Generator Owner shall provide its Protection System settings and scheme types..." The requirement should state in unambiguous terms what needs to

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	be provided. Likewise the statements tin R2.3 and 2.4 "...making any system configuration change..." should be stated so that it is clear that types of changes warrant action.
Response: The drafting team appreciates your support. **1. If the Generator Owner owns transmission lines (such as between the GSU and transmission yard), they will need to provide those impedances. The reason for including those protective devices that trip the generator is that they may also respond to transmission faults and therefore would need coordination.** **2. Protection System is a defined term in NERC's glossary. The list of relays in the reference document are not meant to be all inclusive but more of a list for guidance.** **3. The definition was developed to better define what coordination means within the standard as the existing PRC-001-1 Standard often means "communicate" when "coordinate" is used. The drafting team has modified the standard for clarity.** **4. The drafting team believes that Requirement R1 is specific considering the variety of protective devices that an entity may use. Similarly, it would be difficult to provide an inclusive list of changes that apply to Requirement R2, Parts 2.3 and 2.4. The drafting team has opted not to provide specific examples but more clarification has been added to Requirements R2 and R3 concerning "system configuration change" requiring the Owner to determine if his changes impacts the System Protection Coordination with the interconnected owner.**	
Y-W Electric Association, Inc.	We are concerned that this standard may place undue burden on small entities, particularly DPs, that will suddenly be required to participate in extensive coordination with other entities, even if the small entity is not the entity that is performing any protection system upgrades. While the overall goal of this standard is very appropriate, there appears to be little to no flexibility in the implementation of it. No thought seems to have been given to the impact that this standard may have on very small distribution providers with limited resources and, in many cases, no in-house engineering expertise to handle these requirements. This should be very carefully considered as the standard is finalized.
Response: The drafting team believes that most small Distribution Providers will not be an applicable entity for this standard. The drafting team has modified the Applicability portion of the standard in this regard to include only "Distribution Providers that own transmission Protection Systems."	
FirstEnergy	We would like to thank the SDT for their hard work in revising this standard. We would, however, like to offer the following comments: 1. Regarding requirements R2 and R3 reference Attachments 1, 2, and 3, FE believes the attachments are overly prescriptive and are more procedural rather than establishing reliability compliance requirements. The attachment steps may be better suited for a guideline document to provide assistance to industry in implementing portions of the standards requirements. 2. If the attachments remain, we see potential compliance issues with the inclusion of these requirements in an attachment. For example, Req. R2 is applicable to the Generator Owner (GO) who is responsible for completing the actions in

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	accordance with Att. 1. The problem is that Steps 2, 3, 5, and 6 of Att. 1 places specific requirements on the Transmission Owner (TO) and the applicable Distribution Provider (DP). As presently structured these attachments are troublesome for successful compliance enforcement. Also, the "condition" to take these actions within 6 months of the proposed in-service date is an important requirement that gets somewhat lost in the attachments and should be explicit in the body of the requirements. Therefore, the only way to hold the appropriate entities responsible for their required actions is to move these actions into the body of the Requirements of Sec. B of the standard and eliminate the attachments. 3. Requirement R1 is too broad with regard to what Protection System settings must be provided. It should be clear that only the settings of the interconnected Facilities are required. We suggest adding the phrase "of its interconnected Facilities" after "Protection System settings and scheme types". 4. Req. R5 Part 5.1 and Req. R6 Part 6.1 have expiration dates (6 months following the effective date of the Standard) which are Implementation Plan issues that should not be specified as a requirement in this standard. We understand that the SDT may be concerned with sanctionability of these requirements; however, not meeting the Implementation Plan requirements also results in noncompliance. Therefore, we suggest removing Parts 5.1 and 6.1 and integrating this information into the Implementation Plan. Also, it is not clear what is required to fulfill Parts 5.1, 5.2, 6.1 and 6.2. FE believes it would be appropriate to provide general information to the type of Protection System design implemented at various BES voltage levels indicating the type of primary protection schemes utilized, where full equipment redundancy exists, the type of back-up schemes implemented, where carrier communications are utilized, etc. However, detailed information regarding the location and implementation on a circuit by circuit basis is overly burdensome. If it is required to provide a detailed description of every Protection System scheme for each circuit, six months would not be adequate. It also would be burdensome because most of this information should have already been provided. If only a general description of each type of scheme is required, would you also need to provide a list of locations and circuits the scheme type is applied? 5. Requirement R6 is not appropriate for an entity that acts as both the Generator Owner and Generator Operator for a specific function. We ask that the SDT consider adding wording to the requirement to allow exceptions for these situations.

Response: The drafting team appreciates your support.

1. The most critical aspect of this Standard is "To ensure that System Protection Coordination is achieved" as stated in the Purpose. Effective and timely sharing of information between entities helps achieve this purpose. Reviewing the shared information (i.e., reviewing device settings) and responding to their adequacy as outlined in the attachments further helps to achieve this purpose by requiring "peer review". Review of shared information implies that fault and coordination studies will be performed based upon the provided information and the results will be compared and agreed upon between affected entities. The process as outlined in the attachments ensures System Protection Coordination is achieved and does impact reliability.

2. The drafting team thanks you for your comment. The drafting team has made changes to Requirements R2 and R3 and the Attachments so that Requirement R2 solely applies to the GO. Similarly, Requirement R3 only applies to TOs and DPs that own transmission Protection Systems. The

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Attachments are a part of the standard and must be considered, and do hold the appropriate entities responsible. 3. The drafting team has modified Requirement R1 – and limited the scope of information to that which is "requested" and added the phrase, ". . . to the interconnected Facility owners. . . " to limit the number of entities the information must be shared with. 4. The drafting team has reviewed your suggestion and does not believe that Requirement R5, Part 5.1 and Requirement R6 Part 6.1 needs to be removed. The intention of Requirement R5, Part 5.1 was to provide the Transmission Operator with information on existing schemes applied on a general basis. Therefore, there could be a single description of an entities' DCB scheme, Permissive Overreaching Transfer Trip scheme, etc. Requirement R5, Part 5.2 does the same action for new schemes. The intentions of Requirement R6, Parts 6.1 and 6.2 were similar to Requirement R5, Parts 5.1 and 5.2 respectively except that information is to be provided to the Generator Operator. Since the detailed information is not required, to meet Parts 5.1 and 6.1, the drafting team believes that 6 months is sufficient. A list of locations and circuits where each scheme type is applied would be useful but it is not required to satisfy Parts 5.1 and 6.1. 5. The drafting team does not believe that the situation described makes a difference in the need to follow Requirement R6 as the part of the entity that acts as the Generator Operator will need this Protection System information from the part of the entity that acts as the Generator Owner to effectively function in its role.	