NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments
Project 2007-11 Disturbance Monitoring

The Disturbance Monitoring Drafting Team thanks all commenters who submitted comments on the SAR. These standards were posted for a 45-day public comment period from November 1, 2013 through December 16, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 76 sets of comments, including comments from approximately 205 different people from approximately 157 companies representing all 10 Industry Segments as shown in the table on the following pages.

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

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

Summary Consideration

In response to numerous comments, the SDT has agreed to remove the proposed definitions from the draft standard. The SDT received a comment to revise and use the existing term Disturbance Monitoring Equipment (DME) instead. The SDT has developed the standard to focus on data rather than equipment. The SDT considered revising or retiring the defined term, DME. The SDT reviewed the body of NERC Standards and found the only reference to DME is in PRC-002-1 and PRC-018-1 which will both be replaced by PRC-002-2 upon its approval, and decided to leave the definition as is. The draft standard includes requirements for sequence of events recorder (SER) data, fault recorder (FR) data and dynamic disturbance recorder (DDR) data.

The comments received regarding the methodology in Attachment 1 were directed at Requirements R1 and R2, and Attachment 1. Comments were specifically addressed at explaining "location", station configurations, and equipment ownership. The Drafting Team intended that the bus location be the bus location identified in a system study, and further identifies it in Attachment 1 as "For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus." There are cases where buses contain Elements that the Transmission

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Owner does not own. In these instances, the Transmission Owner identifies the bus and then notifies the owners of any Elements that it does not own.

Comments were received on the selection of the Entities identified in the Applicability Section. The PC and RC are included because they have an overall view of the BES to be what BES Elements need to be included for DDR. Responsible Entity was used by the SDT to reflect the fact that the Planning Coordinator and Reliability Coordinator have different functions across the continent. Comments were received that pointed to the hardware for capturing data. This standard is not about "how" the data is captured, but "what" data is captured. The need for generator data was questioned. During wide-area or slowly evolving disturbances, generator reaction is crucial to the reconstruction and understanding of an event.

The comments received regarding Requirement R6 (now R5) indicated that stakeholders believed the requirement demanded DDR data capture on an excessive number of BES Elements. The SDT revised the requirement to address these comments by:

- Instead of monitoring all Elements of IROLs, monitor one or more
- Instead of monitoring all Elements of permanent Flowgates and transmission interfaces, monitor "Any one BES Element associated with major transmission interfaces…"

The Parts/sub-Parts of what is now Requirement R5 were rearranged for clarity.

The concerns of most of the comments received regarding the Implementation Plan were directed at the length of time required for implementation of Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10), and R13 (now R11). The schedule for implementation is now to be at least 50% compliant within three (3) years following notification of the list, and 100% compliant within five (5) years following notification of the list. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be 100% compliant within five (5) years following notification of the list.

Based on stakeholder comments, the DMSDT made significant revisions to PRC-002-2 including:

- Combined Requirements R1 and R2.
- Combined Requirements R6 and R7.
- Removed references to "equipment" and specified data requirements for FR, SER and DDR.

- Removed references to “locations” and replaced “bus” with “BES bus”
- Updated rationales with clarifications and more general information for each requirement.
- Revised Requirement R6 (now R5) for more clarity regarding DDR data requirements.
- Revised the VSLs to conform to the revised requirement language.
- Added language to the Guidelines and Technical Basis section of the standard.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
2.	Paul Jackson	Buckeye Power, Inc.	RFC	3, 4
3.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
4.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
5.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
6.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
7.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

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

8. Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. James Burns	Transmission Technical Operations	WECC	1
2. David Heffernan	Transmission SPC Technical Svcs	WECC	1
3. Karin Butler	Transmission SPC Technical Svcs	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Erika Doot	Bureau of Reclamation	X				X					

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Ed Croft	Corporate Compliance/Engineering	X		X		X					

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Mike Garton	Dominion	X		X		X	X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	MRO	6
3.	Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6
4.	Michael Crowley	Virginia Electric & Power Company	SERC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Michael Lowman	Duke Energy	X		X		X	X				

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Pablo Onate	El Paso Electric	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Gustavo Estrada	El Paso Electric	WECC	5
2.	Rhonda Bryant	El Paso Electric	WECC	3
3.	Luis Rodriguez	El Paso Electric	WECC	6
4.	Pablo Onate	El Paso Electric	WECC	1

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

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

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

Additional Member	Additional Organization	Region	Segment Selection
8. Don Cuevas	Beaches Energy Services	FRCC	1
9. Mark Schultz	City of Green Cove Springs	FRCC	3

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

Additional Member	Additional Organization	Region	Segment Selection
1. Paul DiFilippo	Hydro One Networks Inc.	NPCC	1, 3
2. Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Charles Yeung	IRC Standards Reveiw Committee		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Ben Li	IESO	NPCC	2
2. Matt Goldberg	ISONE	NPCC	2
3. Lori Spence	MISO	MRO	2
4. Greg Campoli	NYISO	NPCC	2
5. Cheryl Mosely	ERCOT	ERCOT	2
6. Stephanie Monzon	PJM	RFC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Tom McElhinney	JEA	X		X		X					

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Jose Conto	Modeling Working Group										

No Additional Responses

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Russel Mountjoy	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6

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

4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madison Gas and Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	Midcontinent Independent System Operator	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Bos	Muscatine Power and Water	MRO	4
14.	Scott Nickels	Rochester Public Utilities	MRO	4
15.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
17.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Cole Brodine	Nebraska Public Power District (NPPD)	X		X							

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Saul Rojas	New York Power Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Wayne Sipperly	NYPA	NPCC	5
2.	David Rivera	NYPA	NPCC	3
3.	Bruce Metruck	NYPA	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19. Group	Allen Schriver	North American Generator Forum - Standards Review Team (NAGF-SRT)					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Shultz	Southern Company	SERC	5
2.	Stephen Berger	PPL Generation, LLC	RFC	5
3.	Dan Duff	Liberty Electric Power	RFC	5

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

Additional Member	Additional Organization	Region	Segment Selection
4. Dana Showalter	E.ON Climate & Renewables	ERCOT	5
5. Joe O'Brien	NIPSCO, Hammond	RFC	5

				1	2	3	4	5	6	7	8	9	10
20.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Granffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5

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

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

				1	2	3	4	5	6	7	8	9	10
22.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	Louisville Gas and Electric Company and Kentucky Utilities Company	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

				1	2	3	4	5	6	7	8	9	10
23.	Group	Lucas Oliveira	Reason International, Inc.	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Moacyr Calheiros	Reason International, Inc	NA - Not Applicable	1
2.	Nei Mueller	Reason International, Inc	NA - Not Applicable	1
3.	Fernando Costa Neves	Reason Tecnologia S.A.	NA - Not Applicable	NA
4.	Sergio Zimath	Reason Tecnologia S.A.	NA - Not Applicable	NA
5.	Carlos Dutra	Reason Tecnologia S.A.	NA - Not Applicable	NA

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
24.	Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rene Free	Santee Cooper		1, 3, 5, 6
2.	Tom Abrams	Santee Cooper		1, 3, 5, 6
3.	Bridget Coffman	Santee Cooper		1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
25.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	PAUL NAUERT	AMEREN		
2.	JOHN MILLER	GEORGIA TRANSMISSION CORP		
3.	CHARLES FINK	ENTERGY		
4.	JERRY BLACKLEY	DUKE ENERGY PROGRESS		
5.	JOEL MASTERS	SOUTH CAROLINA ELECTRIC AND GAS		
6.	STEVE EDWARDS	VIRGINIA POWER AND ELECTRIC CO		
7.	DANIEL McNEELY	TVA		
8.	BRIDGET COFFMAN	SANTEE COOPER		
9.	BOB WARREN	BIG RIVERS ELECTRIC COOP		
10.	PHIL WINSTON	SOUTHERN COMPANY SERVICES		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11. DAVID GREENE		SERC RRO											
12. DAN ROETHEMEYER		DYNEGY											
27.	Group	Wayne Johnson	Southern Company	X		X		X	X				
No Additional Responses													
28.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Andy Evans	Westar Energy	SPP	1, 3, 5, 6
2.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
3.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
4.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
5.	Shannon Mickens	Southwest Power Pool	SPP	2
6.	Jim Nail	City of Independence, MO	SPP	3
7.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
29.	Group	Chang Choi	Tacoma Power	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Travis Metcalfe	Tacoma Public Utilities	WECC	3
2.	Keith Morisette	Tacoma Public Utilities	WECC	4
3.	Chris Mattson	Tacoma Power	WECC	5
4.	Michael Hill	Tacoma Public Utilities	WECC	6

				1	2	3	4	5	6	7	8	9	10
30.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

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

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

5.	George Pitts		SERC	1
6.	Daniel McNeely		SERC	1
7.	Craig McClure		SERC	1
8.	Karen Ryland		SERC	1
9.	Rusty Hardison		SERC	1
10.	Dale Harris		SERC	1

				1	2	3	4	5	6	7	8	9	10
31.	Group	Lloyd A. Linke	Western Area Power Administration	X					X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Western Area Power Administration	Colorado River Storage Project	WECC	6
2.	Western Area Power Administration	Serria Nevada Region	WECC	1, 6
3.	Western Area Power Administration	Desert Southwest Region	WECC	1, 6
4.	Western Area Power Administration	Rocky Mountain Region	WECC	1, 6
5.	Western Area Power Administration	Upper Great Plains Region	MRO	1, 6

				1	2	3	4	5	6	7	8	9	10
32.	Individual	Joel Charlebois	AESI Acumen Engineered Solutions International Inc.					X					
33.	Individual	David Jendras	Ameren	X		X			X				
34.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
35.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
36.	Individual	John Brockhan	CenterPoint Energy Houston Electric	X									
37.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
38.	Individual	Scott Langston	City of Tallahassee	X		X							
39.	Individual	Bill Fowler	City of Tallahassee (TAL)			X							
40.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
41.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
42.	Individual	Tommy Drea	Dairyland Power Cooperative (DPC)	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
43.	Individual	Dan Roethemeyer	Dynegy					X					
44.	Individual	Brenda Frazer	Edison Mission Marketing & Trading Inc.	X				X					
45.	Individual	Oliver Burke	Entergy Services, Inc.	X									
46.	Individual	Chris Scanlon	Exelon Companies	X		X	X	X	X				
47.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
48.	Individual	Jonathan Meyer	Idaho Power Company	X									
49.	Individual	Michael Falvo	Independent Electricity System Operator		X								
50.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
51.	Individual	Kathleen Goodman	ISO New England Inc.		X								
52.	Individual	Michael Moltane	ITC	X									
53.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
54.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
55.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
56.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
57.	Individual	Karin Schweitzer	Lower Colorado River Authority					X					
58.	Individual	Luminant Energy Company LLC	Luminant Energy Company LLC						X				
59.	Individual	Rick Terrill	Luminant Generation Company LLC					X					
60.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				
61.	Individual	David Kiguel	N/A								X		
62.	Individual	Steve Hill	Northern California Power Agency				X	X	X				
63.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
64.	Individual	Christina Conway	Oncor Electric Delivery	X									
65.	Individual	Catherine Wesley	PJM Interconnection		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
66.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
67.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
68.	Individual	Anthony Jablonski	ReliabilityFirst										X
69.	Individual	Bret Galbraith	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
70.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
71.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
72.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
73.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
74.	Individual	David Thorne*	PEPCO										
75.	Individual	Karen Silverman*	PSE										
76.	Individual	Kathleen Black*	DTE										

*** Comments submitted after comment period closed.**

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

Summary Consideration: The Standard Drafting Team (SDT) thanks the entities below for indicating their participation in other entities' comment submissions. The posted Requirement R6 (revised to what is now number R5) was revised to reflect comments received addressing dynamic disturbance recording data which included Flowgates.

Organization	Agree	Supporting Comments of "Entity Name"
Associated Electric Cooperative, Inc. - JRO00088	Agree	AECI Supports comments posted by SERC PCSIn addition, AECI particularly questions the value and technical rationale for citing all permanent flowgates. There are several types of permanent flowgates, and not all would correlate to the BES Reliability purpose to warrant DDR measurements at either end. Is it this SDT's intent to move the Eastern Interconnection away from flowgate methodology for assessing impact and capacity for commerce across its bulk transmission system? If the other specified technical assessments have merit, then busses terminating any flowgates significant for DDR will show up.
Consolidated Edison Co. of NY, Inc.	Agree	NPCC

Organization	Agree	Supporting Comments of “Entity Name”
Cowlitz PUD	Agree	FMPA's comment submitted by Frank Gaffney
Luminant Energy Company LLC	Agree	Luminant Generation Company LLC
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP
South Carolina Electric and Gas	Agree	SERC PCS

1. Do you support the new definitions for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording? If not, please explain why and provide suggested changes.

Summary Consideration In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard. The DMSDT also received a comment to revise and use the existing term Disturbance Monitoring Equipment (DME) instead. The DMSDT has developed the standard to focus on data rather than equipment, and considered revising or retiring the defined term, DME. The DMSDT reviewed the body of NERC Standards and found the only reference to DME is in PRC-002-1 and PRC-018-1 which will both be replaced by PRC-002-2 upon its approval, and decided to leave the DME definition as is. The draft standard includes sequence of events recording (SER) data, fault recording (FR) data and dynamic disturbance recording (DDR) data.

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	We do not support the proposed definitions because these seem to be straightforward and understandable without proposing additional glossary terms. The Standards DMSDT Guidelines, dated April 2009, states: "The DMSDT should avoid developing new definitions unless absolutely necessary. There is a glossary of terms that has been approved for use in reliability standards. Before a DMSDT adds a new term, the team should check the latest version of the Glossary of Terms for Reliability Standards to determine if the same term, or a term with the same meaning, has already been defined. If a term is used in a standard and the term is defined in a collegiate dictionary, then there is no need to also include the term in the NERC Glossary of Reliability Terms. The addition of an adjective or a prefix to an already defined term should not result in a new defined term. It is very difficult to reach consensus on new terms. If a simple phrase can be used in a standard to replace a new term, then the DMSDT should consider using the phrase rather than trying to obtain stakeholder consensus on the new term."

Organization	Yes or No	Question 1 Comment
		We do not see how these proposed terms are "absolutely necessary." Please provide a rationale why other approaches could not be taken.
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard. DME (Disturbance Monitoring Equipment) is in the NERC Glossary. The DMSDT reviewed the body of NERC Standards and found the only reference to DME is in PRC-002-1 and PRC-018-1 which will be replaced by PRC-002-2 upon approval. The DMSDT decided to leave the DME definition as is in the NERC Glossary.		
Bonneville Power Administration	No	BPA feels the definitions are not succinct enough to explain to someone exactly what it is they're being required to do.
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.		
Florida Municipal Power Agency	No	Please see response to question 7.
Response: Please see the DMSDT response to question 7.		
Hydro One Networks Inc.	No	The definition for SOER optionally includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit breaker position. The purpose of the standard is to "have adequate data available to facilitate analysis of BES disturbances". We don't see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis.
Response: The DMSDT believes that having SER and FR data as specified in the current draft of the standard is sufficient for understanding the nature of a large scale power system disturbance and for effective post-event analysis. NERC's Event Analysis		

Organization	Yes or No	Question 1 Comment
group reviewed and agreed with this approach proposed by the DMSDT. Having precise information on sequence of operation of protection equipment may be of interest for detailed analysis of protection system performance. Having such capability is a technical and business decision that is left up to the individual Entities to make.		
New York Power Authority	No	The definition for SOER optionally includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit breaker position. The purpose of the standard is to "have adequate data available to facilitate analysis of BES disturbances". We don't see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis.
Response: The DMSDT believes that having SER and FR data as specified in the current draft of the Standard is sufficient for understanding the nature of a large scale power system disturbance and for effective post-event analysis. NERC's Event Analysis group reviewed and agreed with this approach proposed by the DMSDT. Having precise information on sequence of operation of protection equipment may be of interest for detailed analysis of protection system performance. Having such capability is a technical and business decision that is left up to the individual Entities to make.		
Northeast Power Coordinating Council	No	The definition for SOER optionally includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit breaker position. The purpose of the standard is to "have adequate data available to facilitate analysis of BES disturbances".

Organization	Yes or No	Question 1 Comment
		We don't see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis. We could support the definitions as used within this standard but do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should be given to using the word "data" in place of the word "recording", such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD. Also the definition of SOER presently uses the phrase "... status of Elements, which may include protection and control devices." We recommend changing the word "Elements" to "circuit breakers" which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status.

Response: The DMSDT believes that having SER and FR data as specified in the current draft of the Standard is sufficient for understanding the nature of a large scale power system disturbance and for effective post-event analysis. NERC's Event Analysis group reviewed and agreed with this approach proposed by the DMSDT. Having precise information on sequence of operation of protection equipment may be of interest for detailed analysis of protection system performance. Having such capability is a technical and business decision that is left up to the individual Entities to make.

In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.

Organization	Yes or No	Question 1 Comment
The DMSDT decided to use the acronyms SER for sequence of events recording, FR for fault recording, and DDR for dynamic disturbance recording. **The wording in Requirement R3 (now R2) has been revised for clarification.**		
Santee Cooper	No	We agree with the SERC PCS comments.
Response: Please see the response to the SERC PCS below.		
SERC Protection and Controls Subcommittee	No	The SERC PCS requests that the DMSDT to make the following changes: 1. Add 'balanced, three phase' between 'dynamic' and 'power' in order to clarify the context of Dynamic Disturbance Recording. Thus it would read 'The recording of time sequenced data for dynamic balanced, three phase power system characteristics such as power swings, frequency variations, and abnormal voltage problems.' 2. Also the definition of SOER presently uses the phrase "... status of Elements, which may include protection and control devices." We recommend changing the word "Elements" to "circuit breakers" which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status. 3. We do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment.

Organization	Yes or No	Question 1 Comment
		When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should be given to using the word “data” in place of the word “recording”, such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD.
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard. The DMSDT decided to use the acronyms SER for sequence of events recording, FR for fault recording, and DDR for dynamic disturbance recording.		
SPP Standards Review Group	No	To maintain parallel structure in the definition of Dynamic Disturbance Recording (DDR) we suggest changing ‘abnormal voltage problems’ to ‘abnormal voltage deviations’. The acronym for Fault Recording (FR) may be confused with that of Frequency Response as has been previously defined in BAL-003. Would it be prudent to change one or the other?Insert ‘which’ in the next to last line of the Rationale Box such that it reads ‘...proliferation of multiple function devices, and the intent of the Standard which is to address the result, not the how...’
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.		
Tacoma Power	No	What is the purpose of the following clause in the definition of SOER: “...which may include protection and control devices”? Since the focus of

Organization	Yes or No	Question 1 Comment
		this definition is on recording, and not equipment, consider removing this clause.
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.		
Ameren	No	(1) Ameren also supports the SERC Protection & Control Subcommittee (PCS) comments and hereby includes them by reference rather than repeating them all.
Response: Please see the response to SERC PCS.		
American Electric Power	No	Sequence of Events Recording (SOER) - This definition should only specify functionality and *not* attempt to define scope. Instead, we suggest "The recording of time sequenced data for change in status of a monitored, binary value". Fault Recording (FR) - Again, this definition should only specify functionality and *not* attempt to define scope. Instead, we suggest "The recording of time-sequenced waveform data for a monitored analog value."
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.		
Dairyland Power Cooperative (DPC)	No	R4. If information is required to be gathered for every transmission line connected to the bus, equipment may need to be installed to capture this information. The capital cost may be significant to some smaller TO's to install the FR equipment capable to capture this information. The DMSDT is encouraged to consider this fact in regards to this requirement and in the implementation plan.

Organization	Yes or No	Question 1 Comment
Response: The DMSDT notes that this is a data standard and that many entities may already have adequate data recording capability to meet the intent of the requirements. The standard calls for entities to analyze their systems and be able to provide data based on that analysis. The CEAP for this project was posted to collect industry cost data.		
Entergy Services, Inc.	No	1) Add “balanced three phase” between “dynamic” and “power” in order to clarify the context of Dynamic Disturbance Recording. The revised definition would be “The recording of time sequenced data for dynamic, balanced three phase power system characteristics such as power swings, frequency variations, and abnormal voltage problems.” 2) The definition of SOER presently uses the phrase “... status of Elements, which may include protection and control devices.” Recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also, the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status. 3) Recommend not using the acronyms SOER, FR, and DDR as defined NERC Glossary acronyms. These acronyms have historically been used by industry to label the recording equipment; therefore the same acronym should not be used when referring to the equipment’s data.
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard. **The DMSDT decided to use the acronyms SER for sequence of events recording, FR for fault recording, and DDR for dynamic disturbance recording. They will not be defined in the NERC Glossary.**		
N/A	No	The proposed definition of SOER indicates that it may include protection and control devices. However, R3 only specifies the recording of circuit

Organization	Yes or No	Question 1 Comment
		breaker position (open/close). The purpose of the standard is to "have adequate data available to facilitate analysis of BES disturbances." In order to permit for a comprehensive analysis of disturbances some basic protection device information is necessary and should not be optional in the definition. I suggest replacing "may include" with "includes."
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.		
Wisconsin Electric Power Company	No	1. DDR definition: The phrase "abnormal voltage problems" is redundant. Suggest definition be changed to: The recording of time sequenced data for dynamic power system characteristics such as power swings, frequency variations, or abnormal voltage conditions. 2. SOER definition: Need to specifically identify circuit breakers, which are the primary Elements needed for SOER as indicated in Requirement 3. Suggest it be changed to: The recording of time sequenced data for change in status of Elements, particularly circuit breakers, and including other protection and control devices as needed.
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.		
City of Austin dba Austin Energy	No	

Organization	Yes or No	Question 1 Comment
Colorado Springs Utilities	No	
Dominion	Yes	We could support the definitions as used within this standard but do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should be given to using the word “data” in place of the word “recording”, such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD.Also the definition of SOER presently uses the phrase “... status of Elements, which may include protection and control devices.” We recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status.

Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard. The DMSDT decided to use the acronyms SER for sequence of events recording, FR for fault recording, and DDR for dynamic disturbance recording.

The wording in Requirement R3 (now R2) has been revised for clarification.

Organization	Yes or No	Question 1 Comment
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration L.P. agrees with the strategy the project team has taken to focus on the output of recorders - not the devices themselves. Recording technology is rapidly evolving and equipment-related requirements may be quickly be outdated otherwise.
Response: Thank you for your comment.		
Texas Reliability Entity	Yes	In the definition of Dynamic Disturbance Recording, we would suggest including phasors in the list of power system characteristics. This would be useful in applying DDRs at locations where there may be angular stability concerns or subsynchronous resonance concerns.
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.		
Arizona Public Service Company	Yes	
Bureau of Reclamation	Yes	
Corporate Compliance/Engineering	Yes	
El Paso Electric	Yes	
IRC Standards Reveiw Committee	Yes	
MRO NSRF	Yes	
Nebraska Public Power District (NPPD)	Yes	

Organization	Yes or No	Question 1 Comment
North American Generator Forum - Standards Review Team (NAGF-SRT)	Yes	
Pepco Holdings Inc & Affiliates	Yes	
PPL NERC Registered Affiliates	Yes	
Reason International, Inc.	Yes	
Southern Company	Yes	
Tennessee Valley Authority	Yes	
Western Area Power Administration	Yes	
AESI Acumen Engineered Solutions International Inc.	Yes	
American Transmission Company, LLC	Yes	
CenterPoint Energy Houston Electric	Yes	
City of Tallahassee	Yes	
City of Tallahassee (TAL)	Yes	
Dynegy	Yes	

Organization	Yes or No	Question 1 Comment
Edison Mission Marketing & Trading Inc.	Yes	
Exelon Companies	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
ITC	Yes	
Kansas City Power & Light	Yes	
LCRA Transmission Services Corporation	Yes	
Liberty Electric Power LLC	Yes	
Lower Colorado River Authority	Yes	
Manitoba Hydro	Yes	
Northern California Power Agency	Yes	
Oncor Electric Delivery	Yes	
PJM Interconnection	Yes	
Public Service Enterprise Group	Yes	

Organization	Yes or No	Question 1 Comment
ReliabilityFirst	Yes	
Xcel Energy	Yes	
Duke Energy		Duke Energy recommends the following suggestion to the new definitions (1) Dynamic Disturbance Recording (DDR) -The recording of time sequenced data for dynamic power system analysis comprising characteristics such as power flow, and frequency and voltage excursions. (2) Fault Recording (FR) -The recording of time sequenced waveform data, such as current(s) and voltage(s), for short circuits or failure of BES Elements. 3) Sequence of Events Recording (SOER) -The recording of time sequenced data for change in status of BES Elements, which may include components of protection and control systems.
Response: In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.		

2. **Do you agree with the methodology in Requirement R1 that selects the BES bus location for Sequence of Events Recording and Fault Recording? If not, please provide technical justification.**

Summary Consideration: The comments received were directed at Requirements R1 and R2, and Attachment 1. Comments were specifically addressed at explaining "location", station configurations, and equipment ownership. The DMSDT intended that the bus location be the bus location identified in a system study, and further identifies it in Attachment 1 as "For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus." There are cases where buses contain Elements that the Transmission Owner does not own. In these instances, the Transmission Owner identifies the bus and then notifies the owners of any BES Elements that it does not own.

Organization	Yes or No	Question 2 Comment
ACES Standards Collaborators	No	We concur with the DMSDT's observation and rationale that there is no need to monitor disturbances for small systems in the same manner as large systems. However, we believe this standard should require an entity to generate its own methodology that identifies how it will determine locations to install Fault Recording and Sequence of Events Recording devices and supporting equipment and how often it will conduct these assessments. We feel the method proposed for selecting bus locations is too restrictive and could be subject to interpretation from auditors when not properly followed.
Response: The Purpose of PRC-002-2 is "To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances." From post 2003 Blackout event analysis, it was clear that the industry needed direction on what data needed to be		

Organization	Yes or No	Question 2 Comment
captured. This standard addresses that need. The methodology developed is consistent with good engineering principles and operational practice. The DMSDT constructed Requirement R1 to not have any fill-in-the-blank concerns. **The Methodology uses readily available data that it is not overly restrictive.**		
Corporate Compliance/Engineering	No	The document "Mapping of Standard's Introduction of BOT Approved PRC-002-1 to Proposed PRC-002-2" from January 2013 described line terminals above 200 kV and large generators/transmission stations which warrant this level of data gathering, as they represent the backbone of the transmission system. It would be better to start with this system level first and test out data collection. For the sake of comparison, the approximate median value of the 11 highest (short circuit) MVA PSE buses where digital fault recorders are already in place, is 6800 MVA. Lowering to a short circuit MVA level of 1500-2500 MVA quadruples the quantity of collection sites.
Response: For the purpose of PRC-002-2, a minimum number of locations for SER and FR are required to facilitate sufficient coverage and data for analyzing large system events. Based on these concepts, the DMSDT developed a procedure included in Attachment 1 – SOER and FR Locations Selection Methodology (Attachment 1 has been renamed to Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data (Requirement R1)) that utilizes the maximum available calculated three phase short circuit MVA. Using this methodology helps ensure sufficient coverage while accounting for variations in size and system strength of Transmission Owners across all the Interconnections. Additionally, this methodology provides flexibility in the selection process. **The comparison provided indicates that the lower threshold would be 6800 MVA and not 1500 MVA.**		
Florida Municipal Power Agency	No	Please see response to question 7.

Organization	Yes or No	Question 2 Comment
Response: Please see the DMSDT response to Question 7.		
Hydro One Networks Inc.	No	This requirement (and associated Attachment 1) requires some clarity before we can determine if we agree with the methodology. This may be a bit problematic with the BES definition not confined to busses. What is a BES bus location? Does this mean the entity gathers information on all fault levels for busses which contain at least one BES Element?
Response: The DMSDT intended that the bus location be the bus location identified in a system study, and further identifies it in Attachment 1 as "For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus." "Location(s)" was removed from Requirement R1, and its use in Attachment 1 revised for clarification.		
IRC Standards Review Committee	No	We agree with R1, but we do not see the need for R2 since through R1 and Attachment 1, each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR). There is not another owner(s) that a TO needs to communicate the list to, unless the "list of BES bus locations that it owns" depicted in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that is the case, then Step 1 in Attachment 1 needs to be clarified to distinguish the need for R1 and R2.
Independent Electricity System Operator	Yes	We agree with R1, but we do not see the need for R2 since through R1 and Attachment 1, each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR).

Organization	Yes or No	Question 2 Comment
		There is not another owner(s) that a TO needs to communication the list to, unless the "list of BES bus locations that it owns" depicted in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that's the case, Step 1 in Attachment 1 needs to be clarified.
Response: In Requirement R1 the TO may identify elements that it does not own and therefore Requirement R2 is required for those entities to be notified. Requirements R1 and R2 were combined into what is now R1 as well as their Rationale Boxes. The Rationale Box for R1 provides an explanation.		
JEA	No	The 1500 MVA selection criteria is too low. It needs to be substantially increased.
Response: For the purpose of PRC-002-2, a minimum number of locations for FR and SOER (now SER) are required to facilitate sufficient coverage and data for analyzing large system events. Based on these concepts, the DMSDT developed a procedure included in Attachment 1 – SOER and FR Locations Selection Methodology (Attachment 1 has been renamed to Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data (Requirement R1)) that utilizes the maximum available calculated three phase short circuit MVA. Using this methodology helps ensure sufficient coverage while accounting for variations in size and system strength of Transmission Owners across all the Interconnections. This methodology also provides flexibility in the selection process.		
MRO NSRF	No	For R1 - Add wording that would only obligate each Transmission Owner to identify BES bus locations where it owns Elements with wording like, ". . . Each Transmission Owner shall identify BES bus locations where it owns Elements . . ."
Response: There are cases where buses contain Elements that the Transmission Owner does not own. In these instances, the Transmission Owner identifies the bus and then notifies the owners of any Elements that it does not own.		

Organization	Yes or No	Question 2 Comment
Nebraska Public Power District (NPPD)	No	For step 1 in Attachment 1 please confirm the following: For a 115kV and a 345kV bus in the same substation on the same ground grid is this considered two bus locations such that these would be used in step 3 as two of the 11 buses to calculate the median? For step 7 in Attachment 1 if I have a 230kV bus and a 345kV bus in the same substation in my top 10% is this acceptable to count them as two buses that require FR/SOER since it is a single location? Is this indicating that both buses need to meet the FR/SOER requirements? Please clarify for Attachment 1: Should a 115kV tap substation with no breakers but only a load serving transformer with a high side breaker be included in the fault bus list? It appears they should but would a tap sub with no breakers be required to have FR or SOER? Should generator GSU 13.8kV buses and tie transformer tertiary 13.8kV buses be in the bus fault list? Example list 1 appeared to have some 13.2kV buses but the instructions do say to use 100kV and above. Please confirm only 100kV or above buses should be used.
Response: Correct. In the example presented the 115kV and 345 kV are treated as two bus locations. **Correct. In the example presented the 230 kV and 345 kV are treated as two bus locations and since they are in the top 10%.** **The exact situation described is not clear. Please review the BES Definition Guidelines Document. If your example does not include BES buses, then it would not be included.**		
New York Power Authority	No	The methodology in Attachment 1 is overly complicated (9 steps); and following eight of these required steps, it is then left up to the T.O. to add

Organization	Yes or No	Question 2 Comment
		"discretionary" stations, if desired. Just using the highest 11 station fault MVA values may not be the most accurate. Contributions from a foreign, nearby utility can raise a station's fault values, even though the station itself is not that critical to the listing entity. Using "Station" instead of "Bus" or "Location" would be more definitive. e.g. a 230 kV "Station", a 345 kV "Station",...). The term "bus" can be defined in different ways, so can "location."
Response: For the purpose of PRC-002-2, a minimum number of locations for FR and SER are required to facilitate sufficient coverage and data for analyzing large system events. Based on these concepts, the DMSDT developed a procedure included in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. Using this methodology helps ensure sufficient coverage while accounting for variations in size and system strength of Transmission Owners across all the Interconnections. Additionally, this methodology provides flexibility in the selection process. **In the previous version of the draft standard "station" was used and the DMSDT received numerous comments to change it. The DMSDT developed the current methodology used in the current draft standard. We have revised Step 1 of the attachment to explicitly define what a bus is "For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus."**		
PPL NERC Registered Affiliates	No	These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, PPL; Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

Organization	Yes or No	Question 2 Comment
		The TOs have the system specific knowledge as to where on their networks, SOERs, FRs and DDRs should be installed to effectively capture disturbance data. Many TOs have existing DME equipment in place (previously specified per the Regional Entities) which provides the relevant system disturbance data required for disturbance analysis. The R1, R6 requirements may lead to installation of redundant equipment. Perhaps the R1, R6 requirements should specify that the TOs evaluate where SOERs and FRs are to be installed to effectively capture disturbance data? Re-specifying DME installation per PRC-002-2 may result in redundant evaluation and equipment installation of DMEs. Previous electric sector DME efforts driven by PRC-002-1 and Regional Criteria should be recognized in the specifications for DME installations.
Response: TOs do have the knowledge for SER and FR placement. The Responsible Entity - the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection - has the best wide-area view of the BES and is most suited to be responsible for determining the Elements for which DDR is required. **The standard addresses "what" data must be captured, not "how" it is captured. The intent of the standard is not to require redundancy, and if the data is already captured it does not have to be done again.**		
Reason International, Inc.	No	Several problems in the correct operation of protective measures are related as reflexes of unmitigated harmonics influencing the actuation of protective relays. Industrial plants with high nonlinearities and intense electric power consumption have large influence in the interconnection to the transmission system. The harmonic distortions introduced by these industrial plants range from low to very high orders, up to the 20th harmonic. These distortions may lead to measurement errors and the

Organization	Yes or No	Question 2 Comment
		incorrect operation of protective relays. To avoid aliasing the sampling rate needed to analyze such events, capturing up to the 24th harmonic, should be 48 samples per cycle. Fault recording should therefore be carried out at a minimum of 48 points per cycle, above the typically used 16 points per cycle of protection algorithms.
Response: The DMSDT is not aware of widespread BES disturbances being caused by harmonics generated by industrial facilities. The DMSDT does recognize that anything can happen. The DMSDT feels that the 16 sample per cycle recording rate as specified in Requirement R5 (requirement number revised to R4) is adequate. If an entity determines that a higher recording rate is needed, that data capture characteristic can be used.		
Tacoma Power	No	The 1500 MVA fault level includes many busses that are relatively unimportant to the BES. For example, in the 115 kV portion of our system, 83% of buses have fault levels above 1500 MVA. On our system, fault levels of 4000 MVA are a much better indication of buss important to the overall BES. However, rather than create a new MVA criteria in this standard, we suggest using criteria developed for other standards that determine important subsets of the BES. The requirements in CIP-002-5 R2.5 define substations that have a “medium” impact on the BES. Requiring a FR at a substations classified as “low” is overly burdensome. Alternatively, substations that do not have circuits subject to PRC-023-2 applicability section 4.2.1 should be except from FR requirements. Although we already have fault recorders on all 115 kV transmission substations with more than 3 lines, the purposed methodology would require additional Fault Recorders. These additional fault recorders would

Organization	Yes or No	Question 2 Comment
		provide very little additional data, because the existing fault records include the remote ends of almost all transmission lines. The proposed standard does not take into adequate account the industry progress towards GPS synchronized microprocessor based relays. Much of the data required by FR is already recorded by relays. However, relay records only count as FR if they meet all the FR requirements for the entire substation. Rather than focus on obtaining 100% coverage of quantities at substations, this standard should facilitate taking advantage as much as possible of already installed hardware.
Response: Attachment 1 provides a mechanism for adjusting the three phase short circuit MVA threshold. Steps 3-6 provide an adjustment which can raise the lower threshold to > 1500 MVA. **The comments regarding CIP-002-5 part 2.5 are outside of the scope of this project.** **The standard addresses "what" data must be captured, not "how" it is captured** **To be compliant with this standard an entity needs to have 100% coverage of selected buses.**		
American Electric Power	No	Fault analysis programs such as ASPEN include tap busses to provide connection points for distribution transformers, series capacitors, three-terminal lines, etc. Since these connection points do not have circuit breakers associated with them they are not appropriate locations for disturbance monitoring. However, when applying the Attachment 1 process, these tap busses could show up and possibly distort the Attachment 1 data. The fault summary feature in ASPEN has a check box to ignore tap busses. AEP requests that this feature be utilized in the

Organization	Yes or No	Question 2 Comment
		Attachment 1 process.AEP is concerned that the "top 10%" requirement could force the installation of fault recording devices to be installed at a station with only 2 BES sources. An example is a protected load bus with only 2 BES elements that is connected to stations which meet the requirement and have fault recording devices installed. In this case, both of the stations remote to the protected load bus are BES buses in the top 10% of a TO's bus listing. The standard should not require DFR/SER at those locations. AEP's position is that the standard should focus on fault information availability after an event that allows for accurate analysis and not on over-saturation of fault recording equipment that will require monitoring and maintenance to ensure that the equipment is in service when needed. R2 states that TOs must notify owners of Elements that those elements require SOER/FR. However, the process identified in R1 does not establish a requirement to identify BES Elements. This does not account for the fact that not all elements on the identified busses should require SOER/FR. AEP suggests that the DMSDT add a new R1.3 to state "For each bus identified per 1.1, the Transmission Owner shall identify the BES elements that require FR and the BES interrupting devices that require SOER". The draft can be interpreted to require TOs to dictate to GOs and IPPs where they must install FR/SOER. AEP believes it would be inappropriate for TOs to specify FR/SOER locations for GOs and IPPs.

Organization	Yes or No	Question 2 Comment
		While Attachment 1 provides a reasonable method for TOs to produce a list of buses that it owns, R2 will make TOs responsible to keep track of elements within those buses that it does not own. This responsibility should be revised so that TOs can focus on ensuring that they have adequate equipment in place to monitor its system, rather than managing the complex logistics needed to notify GOs and IPPs.
Response: For the purpose of PRC-002-2, a minimum number of locations for FR and SOER are required to facilitate sufficient coverage and data for analyzing large system events. Based on these concepts, the DMSDT developed a procedure included in Attachment 1 – SOER and FR Locations Selection Methodology (Attachment 1 has been renamed to Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data (Requirement R1)) that utilizes the maximum available calculated three phase short circuit MVA. Using this methodology helps ensure sufficient coverage while accounting for variations in size and system strength of Transmission Owners across all the Interconnections. Additionally, this methodology provides flexibility in the selection process. **The DMSDT intended that the bus location be the bus location identified in a system study. Data would have to be obtainable for each of those buses. If the tapped substation was not modeled in a system study as a bus, then it would not be considered a bus. If it was, derived data for it would be acceptable. If there were no breakers, then SOER (revised to SER) would not be required. The standard addresses "what" data must be captured, not "how" it is captured. Requirements R1 and R2 were combined (into what is now R1), and the wording now reads "…identify BES buses for which sequence of events recording (SER) and fault recording (FR) data…", Attachment 1 indicates "To identify monitored BES buses…". Because a "larger" TO might be responsible for a bus where there are Elements owned by another TO, the "larger" TO is the appropriate entity to make notifications. The standard stipulates just notifications. Requirement R2 (R1 and R2 combined into what is now R1) does not specify that the TO is responsible for tracking the Elements it doesn't own.**		
American Transmission Company, LLC	No	The methodology is acceptable, but a requirement should be added before R1 and the present R1 should be modified as noted below.

Organization	Yes or No	Question 2 Comment
		a. Generator Owners should also be obligated to identify applicable bus locations where they own Elements using the Attachment 1 Steps, rather than delegating this obligation to the Transmission Owners. b. Generator Owners will be able to determine maximum available calculated three phase short circuit MVA after PRC-027-1 becomes a mandatory standard because this standard will require Transmission Owners to provide short circuit study information which makes this possible. In the implementation plan for this standard, Generator Owners could be exempt from compliance with R1 until after the applicable regulatory approvals of PRC-027-1. c. In addition, the scope of the bus locations that need to be considered for identification should be explicitly limited to locations where an entity owns Elements. d. Consider wording for the present R1, but new Requirement R2 like, "Each Generator Owner and Transmission Owner shall identify BES bus locations where it owns Elements for Sequence of Events . . ."
Response: a, b, c: The Requirement R1 bus identifications are best selected by the Transmission Owners because they have the overview of the BES, the required tools, information, and working knowledge of their systems to determine these locations. PRC-002-2 is intended to be independent of other standards. **d) Requirements R1 and R2 were combined into a single requirement (into what is now R1). The Transmission Owner identifies buses and the associated Elements which it may not own. For example, a Generator Owner may own a breaker associated with a bus. The Generator Owner is notified of this and then must comply with PRC-002-2 requirements.**		
Dairyland Power Cooperative (DPC)	No	If information is required to be gathered for every transmission line connected to the bus, equipment may need to be installed to capture this

Organization	Yes or No	Question 2 Comment
		information. The capital cost may be significant to some smaller TO's to install the FR equipment capable to capture this information. The DMSDT is encouraged to consider this fact in regards to this requirement and in the implementation plan.
Response: The DMSDT notes that this is a data standard and that many entities may already have adequate data recording to meet the intent of the requirements. The standard calls for entities to analyze their systems and be able to provide data based on that analysis. The CEAP for this project was posted to collect industry cost data.		
Kansas City Power & Light	No	Attachment 1 and the median method results in an excessive number of buses requiring disturbance monitoring for a system (a large amount of tightly interconnected buses within a metropolitan area).
Response: For the purpose of PRC-002-2, a minimum number of locations for FR and SOER (revised to SER) are required to facilitate sufficient coverage and data for analyzing large system events. More information needs to be provided to the DMSDT for it to provide a response.		
Liberty Electric Power LLC	No	Please see the comments of the NAGF SRT. I support their response to this question.
Response: There was no NAGF SRT response to this question.		
Manitoba Hydro	No	The intent of the methodology is good and will help TOs in determining the number of DMEs required. However, the application of the methodology using the provided "Median_Method_Template" is quite cumbersome and could be simplified.
Response: Without any specific comments regarding the methodology, the DMSDT cannot respond to your concern.		

Organization	Yes or No	Question 2 Comment
Northern California Power Agency	No	Seems excessively tedious for all TOs. Transmission Owners need to produce Transmission Studies per TPL standards. Steps 1 & 2 can be obtained from those studies. Steps 3&4 and second paragraph of step 7 seem arbitrary. Why 11? Please justify the second paragraph of step 7.
Response: **Eleven was selected because there is a definite median value. How an entity gets the data to make its determination is not the concern of this requirement. From the experience of the DMSDT, the breakdown of data acquisition requirements in Step 7 will get adequate data to analyze a wide-area system disturbance.**		
ReliabilityFirst	No	Requirement R1, Attachment 1 - ReliabilityFirst questions the rational to not require any Fault Recording and Sequence of Events Recording if there are no buses that fall on the list (i.e. an entity has no buses with maximum available calculated three phase short circuit MVA of 1500 MVA or greater). ReliabilityFirst believes to effectively recreate events using Fault Recording and Sequence of Events Recording data, Transmission Owners that have no buses on the list should still be required, at a minimum, to have at least one BES bus location with Fault Recording and Sequence of Events Recording. It could be required at least one BES bus location with the highest maximum available calculated three phase short circuit MVA. In order to achieve this, ReliabilityFirst recommends the first sentence in Step 7 (“If there are no bus locations on the list: the procedure is complete and no Fault Recording and Sequence of Events Recording will be required. Proceed to Step 9.”), be removed from the methodology.

Organization	Yes or No	Question 2 Comment
		Also, even though ReliabilityFirst believes the template for determining Fault recorder and SOE bus locations is helpful, ReliabilityFirst recommends developing a step by step example detailing the locational selection methodology.
Response: With no buses on the list, the DMSDT decided that data from that "weak" system would not be critical to an analysis of a wide-area disturbance. The DMSDT felt that adequate data would be captured from interconnected entities that had higher levels of fault MVA.		
Colorado Springs Utilities	No	
Northeast Power Coordinating Council	Yes	We agree with the idea behind the methodology, however the term BES bus locations is not defined. The NERC BES definition applies to Elements, not buses. Continuing to Requirement R2, a TO might not have visibility to BES classification of elements it does not own. Planning/Reliability Coordinator would be a more applicable functional entity for this role. They should also be responsible for reaching out to the GO's with notification for SOER and FR. A TO has no authority to perform this function; a GO might also question the bus selection and ask that another TO bus be included instead. The methodology in Attachment 1 is overly complicated (9 steps); and following eight of these required steps, it is then left up to the T.O. to add "discretionary" stations, if desired. Just using the highest 11 station fault MVA values may not be the most accurate. Contributions from a foreign, nearby utility can raise a station's

Organization	Yes or No	Question 2 Comment
		fault values, even though the station itself is not that critical to the listing entity. Using “Station” instead of “Bus” or “Location” would be more definitive. e.g. a 230 kV “Station”, a 345 kV “Station”,...). The term “bus” can be defined in different ways, so can “location.”
Response: The DMSDT intended that the bus location be the bus location identified in a system study, and has revised Attachment 1 to read “For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.” **A "parent" TO will be able to make the notifications necessary to get the appropriate data captured, and authority is not an issue.** **Requirement R2 was included because a TO's contribution to fault levels at another TO's location might not warrant the data collection at the source TO’s location. Requirements R1 and R2 have been combined (into what is now R1).** **The DMSDT made the bus location divisions in Attachment 1 Step 7 based on an analysis of submitted fault level data.** **The DMSDT intended that the bus location be the bus location identified in a system study. ”Location(s)” was removed from Requirement R1, and its use in Attachment 1 revised.** **In the previous version of the draft standard “station” was used and the DMSDT received numerous comments to change it. The DMSDT developed the current methodology used in the current draft standard. We have revised Step 1 of the attachment to explicitly define what a bus is “For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.”**		
SPP Standards Review Group	Yes	Insert an ‘a’ in the 6th line of the 2nd paragraph of the Rationale Box such that it reads ‘...have a significant effect on system reliability and performance. Conversely, locations with a very low short...’We suggest the

Organization	Yes or No	Question 2 Comment
		DMSDT watch for consistency in the use of the adjective ‘three-phase’ throughout all the posted documents. Make sure it is properly hyphenated.
Response: The DMSDT reviewed the standard for consistency and grammar and made appropriate revisions.		
Western Area Power Administration	Yes	Would like more information as to how the 1500 MVA value was decided upon.
Response: 1500 MVA was arrived at based on three phase fault MVA data collected from industry. The DMSDT reviewed the wording to reflect this to the Guidelines.		
Exelon Companies	Yes	We agree but, consider the following comments. The R1 method is designed to assure a minimum level of SOER and FR is available to analyze events. It does so by requiring a certain process must be periodically performed by the entity. This seems to be a good process to ensure that an entity has a minimally acceptable level of monitoring on their system. However, the DMSDT should consider a less burdensome alternative for entities that are working to install modern equipment with FR and SOER capabilities on all their circuits. Once a system includes a high percentage of modern equipment with SOER and FR capability (also see comments to item 7), R1 through R5 are not needed and become purely burdensome compliance items. At our company gathering data to ensure 100% compliance is a high burden activity. An alternative method for entities with high percentages of modern equipment installed might be to provide a list of BES transmission line terminals showing that at least 50% (or another appropriate

Organization	Yes or No	Question 2 Comment
		percentage) of all employ modern equipment with SOER and FR capability (also see comments to item 7). This data is typically available (we keep it on an ongoing basis) with a very minimal effort. Only a very minimal effort should be required for a system that is already highly monitored and doesn't need a standard to force the issue. This method would be an alternative to R1 through R4 (R5 becomes moot when a high percentage of transformers are monitored) which are designed for entities not monitoring their system. The entity would choose which method to use and the effort required on a highly monitored system would be minimized.
PJM Interconnection	Yes	PJM does support the methodology and also is providing the following comments. The R1 method is designed to assure a minimum level of SOER and FR is available to analyze events. It does so by requiring a certain process must be periodically performed by the entity. This seems to be a good process to ensure that an entity has a minimally acceptable level of monitoring on their system. However, the DMSDT should consider a less burdensome alternative for entities that are working to install modern equipment with FR and SOER capabilities on all their circuits. Once a system includes a high percentage of modern equipment with SOER and FR capability (also see comments to item 7), R1 through R5 are not needed and become purely burdensome compliance items. At our company gathering data to ensure 100% compliance is a high burden activity. An alternative method for entities with high percentages of modern equipment installed might be to provide a list of BES transmission line terminals showing that at least 50% (or another appropriate

Organization	Yes or No	Question 2 Comment
		percentage) of all employ modern equipment with SOER and FR capability (also see comments to item 7). This data is typically available (we keep it on an ongoing basis) with a very minimal effort. Only a very minimal effort should be required for a system that is already highly monitored and doesn't need a standard to force the issue. This method would be an alternative to R1 through R4 (R5 becomes moot when a high percentage of transformers are monitored) which are designed for entities not monitoring their system. The entity would choose which method to use and the effort required on a highly monitored system would be minimized.
Response: The standard is designed to provide the requirements to ensure the capture of adequate data to be able to analyze disturbances. The DMSDT has evaluated other alternatives and found that what is presented accomplishes the objective in a reasonable and practical way. (Refer to the response to Question 7 comments).		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration notes that the MVA thresholds applied are generally consistent with those established in EOP-004-2 "Event Reporting" and the criticality criteria used in CIP Version 5. This makes inherent sense, and would encourage the use of similar rules across all NERC standards in order to properly balance regulatory costs against benefits.
Response: Thank you for the comment.		
Texas Reliability Entity	Yes	(1) The DMSDT may want to consider different short-circuit MVA levels based on the voltage or voltage class, i.e. 1500 MVA for 100-200kV, 2500 MVA for >300kV, etc. (2) To insure broader system coverage, the DMSDT may also want to consider including some flexibility in the location criteria in Step 8 of

Organization	Yes or No	Question 2 Comment
		Attachment 1, such as substations > 200kV with 3 or more non-radial line terminals, substations < 200kV with 5 or more non-radial line terminals.
Response: 1500 MVA was decided upon after a statistical analysis of all BES voltage levels. By using the three phase fault MVA criterion the need for breakdown by voltage was alleviated. Step 8 allows discretion on placement of 10% of the required locations to capture data.		
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Bureau of Reclamation	Yes	
Dominion	Yes	
Duke Energy	Yes	
El Paso Electric	Yes	
Pepco Holdings Inc & Affiliates	Yes	
SERC Protection and Controls Subcommittee	Yes	
Southern Company	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 2 Comment
AESI Acumen Engineered Solutions International Inc.	Yes	
Ameren	Yes	
CenterPoint Energy Houston Electric	Yes	
City of Tallahassee	Yes	
City of Tallahassee (TAL)	Yes	
Edison Mission Marketing & Trading Inc.	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Company	Yes	
ITC	Yes	
LCRA Transmission Services Corporation	Yes	
Lower Colorado River Authority	Yes	
Oncor Electric Delivery	Yes	
Public Service Enterprise Group	Yes	

Organization	Yes or No	Question 2 Comment
Lincoln Electric System		LES recommends the DMSDT further clarify the bus selection process included in Attachment 1. As drafted, the current Attachment 1 methodology does not appear to account for substation configurations such as a 115kV tap bus with a radial transformer fed from that bus. Although the radial transformer would not be considered a BES Element, the bus would be considered BES since it carries through-flow on the line. At this substation, there is no relaying and therefore no capability for SEOR or FR. In consideration of this, does the DMSDT intend for this type of bus to be included on the list? By including these busses, the total number of busses, and therefore the total number of substations requiring SEOR and FR, would increase considerably for some entities.
Response: Attachment 1, Step 1 clarifies "For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus." The examples given would be considered as two buses. Data would have to be obtainable for each of those buses. If the tapped substation was not modeled in a system study as a bus, then it would not be considered a bus. If it was, derived data for it would be acceptable. If there were no breakers, then SOER (acronym revised to SER) would not be required.		

3. Are the appropriate functional entities identified in the Applicability section for PRC-002-2?

Summary Consideration: Comments were received on the selection of the Entities identified in the Applicability Section. The PC and RC are included because they have an overall view of the BES to be able to determine what BES Elements need to be included for DDR. Responsible Entity was used by the DMSDT to reflect the fact that the Planning Coordinator and Reliability Coordinator have different functions across the continent. Comments were received that pointed to the hardware for capturing data. This standard is not about "how" the data is captured, but "what" data is captured. The need for generator data was questioned. During wide-area or slowly evolving disturbances generator reaction is crucial to the reconstruction and understanding of an event.

Organization	Yes or No	Question 3 Comment
ACES Standards Collaborators	No	(1) There is confusion over the Planning Coordinator and Reliability Coordinator functions and their respective relationships. As the standard is currently written, both the PC and the RC are subject to the standard in ERCOT? (2) We do not believe any function would benefit from the standard. Industry has already benefitted from the DOE grants to install PMUs and would continue to benefit from these types financial incentives to continue installing PMUs for situational awareness. The existing financial incentives have obviated the need for the standard as evidenced by report on the September 8, 2011 Arizona-California outages. There was sufficient data to analyze the event. NERC should develop a technical guideline on this topic instead of a standard.
Response: Within ERCOT it is the Planning Coordinator or the Reliability Coordinator. **PMUs only provide DDR data, and not fault or sequence of events data.**		

Organization	Yes or No	Question 3 Comment
The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report: **"Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed. A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices."** **Project 2007-11 – Disturbance Monitoring was initiated to address the existing PRC-002-1 "fill in the blank" standard. FERC did not approve or remand PRC-002-1 in its Order No. 693 (March 16, 2007) because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the "fill in the blank" aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). The consolidation of these two Standards will result in a Standard that fully addresses what is necessary to capture power system disturbance data.** **PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data.** **The Disturbance Monitoring recordings are used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.**		
Bonneville Power Administration	No	BPA feels that responsible functional entities - as well as roles and responsibilities - must be clearly identified in the Standards and requirements. As the Standard is currently written, BPA feels that too much credence is given to assumptions outlined in the Standard and, unless clearly defined, these assumptions will not pan out as described.
Response: The DMSDT has identified the correct functional entities through the NERC Functional Model.		

Organization	Yes or No	Question 3 Comment
Florida Municipal Power Agency	No	Please see response to question 7.
Response: Please see the DMSDT response to Question 7.		
IRC Standards Reveiw Committee	No	This is a “fill in the blank” as identified in the FERC Order 693 and was written to be complied with by the RROs for years. We question why there is need for the RC and PC to comply with these. In fact, the Paragraph 81 activities have identified many requirements that are by the FERC’s perspective not consequential or primary for reliability. We do not believe that a mere reassignment from the old RRO entities to the RC or PC that these requirements suddenly become critical to reliability. NERC should consider other avenues to provide entities with methods to acquire fault data for event analysis. The solution to everything we do shouldn’t be a standard. In fact nearly all new relays and digital meters have disturbance recording capabilities, it is possible to acquire data for event analysis without DDR. Since the intent of this standard is primarily to have post-event data available, it can be argued this is not a critical reliability standard. We point out that the NERC Rules of Procedure have a detailed section on disturbance response procedures.
Response: The PC and RC are included because they have an overall view of the BES and to determine what BES Elements need to be included for DDR. The DMSDT has reviewed the requirements in PRC-002 and PRC-018 against the P81 criteria and has retired two requirements. The standard addresses “what” data must be captured, not “how” it is captured. It must be noted that Disturbance Monitoring data can be used to make real-time restoration decisions.		

Organization	Yes or No	Question 3 Comment
The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report: "Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed. A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices." Project 2007-11 – Disturbance Monitoring was initiated to address the existing PRC-002-1 "fill in the blank" standard. FERC did not approve or remand PRC-002-1 in its Order No. 693 (March 16, 2007) because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the "fill in the blank" aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). The consolidation of these two Standards will result in a Standard that fully addresses what is necessary to capture power system disturbance data. PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data. The Disturbance Monitoring recordings are used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events. The Rules of Procedure do not provide specific requirements for Disturbance Monitoring data. The DMSDT was formed to provide those requirements.		
North American Generator Forum - Standards Review Team (NAGF-SRT)	No	Modify the applicability section 4.3 by adding the following parenthetical after Generator Owner: ("Applies to GO only if GO owns a generator output breaker in the TO's system")

Organization	Yes or No	Question 3 Comment
		We made the comment in the 11/19/13 webinar that DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data, GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording and storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. The webinar presenters stated that this would make TOs responsible for monitoring GO equipment, and there is no technical reason for making them do so. We disagree in that disturbances do not originate exclusively in generation plants, and the majority of such events may in fact stem from transmission system problems (as was the case for the Northeast blackout of ‘03). That is, one can just as easily say that R9 makes GOs responsible for monitoring reactions to the TO’s system, and there is no technical reason for making GOs do so. Given this inability to establish a universal cause-vs-effect rule for disturbances the least-total-cost approach should be followed, and centralizing DME makes more sense than splitting it between involved entities (TOs) and those who merely hand-over recordings (GOs). This point was made again in the 12/5/13 NAGF outreach WebEx meeting, and there did not appear to be a strong rationale for having GOs be designated Responsible Entities when they in fact would be mere appendages, i.e. installing what are to them black boxes and handing-over recordings that they don’t understand.
PPL NERC Registered Affiliates	No	PPL made the comment in the 11/19/13 webinar that DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data, GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording and storage infrastructure, and experts in monitoring and maintaining such equipment; stand alone GOs do not.

Organization	Yes or No	Question 3 Comment
		The webinar presenters stated that making R9 pertain to TOs rather than GOs would make TOs responsible for monitoring GO equipment, and there is no technical reason for making them do so. PPL disagrees in that disturbances do not originate exclusively in generation plants, and the majority of such events may in fact stem from transmission system problems (as was the case for the Northeast blackout of '03). That is, one can just as easily say that R9 makes GOs responsible for monitoring reactions to the TO's system, and there is no technical reason for making GOs do so. Given this inability to establish a universal cause-vs.-effect rule for disturbances the least-total-cost approach should be followed, and centralizing DME makes more sense than splitting it between involved entities (TOs) and those who merely hand-over recordings (GOs). This point was made again in the 12/5/13 NAGF outreach webex meeting, and there did not appear to be a strong rationale for having GOs be designated Responsible Entities when they in fact would be mere appendages, i.e. installing what are to them black boxes and handing-over recordings that they don't understand.

Response: GO's applicability in this standard is not confined to just the ownership of breakers. Generating resources along with transmission system components and topology are significant drivers to system stability and dynamic behavior. Dynamic behavior is captured best through dynamic disturbance data rather than fault recording or sequence of events data.

By connecting to the system a generator contributes to System dynamic behavior.

The providers of the data are not necessarily the sole beneficiaries of the data. The requirements in the standard that apply to GO's are limited to the applications where GO's have to provide data for wide-area disturbance analysis. System dynamic behavior is affected by individual generating unit responses.

Organization	Yes or No	Question 3 Comment
Ameren	No	(1) We ask the DMSDT to replace ‘Planning Coordinator’ with ‘Regional Entity’ in 4.1.1 because the Regional Entity has a wider view, and it promotes consistency.
Response: Referring to 4.1.1 in the Applicability Section, the use of Planning Coordinator is consistent throughout the Eastern Interconnection. The Planning Coordinator responsibilities delineated in PRC-002-2 are not necessarily within the scope of a Regional Entity. This would re-introduce the “fill-in-the-blank” elements that FERC ordered to be removed from standards.		
Flathead Electric Cooperative, Inc.	No	Believe that applicability to TO and GO entities should be limited to those with the current equipment capable of the required monitoring and should not de facto create a situation where an entity has to purchase equipment to comply with the requirements of the standard, including the storage and auditing of post-fact information sufficent to meet the requirements.
Response: The standard addresses “what” data must be captured, not “how” it is captured. The standard is not calling for the capturing of inconsequential data.		
Liberty Electric Power LLC	No	Generator should not be a functional entity for this standard. In cases where generators own a breaker on a transmission system, the only requirement should be a breaker status signal, which properly should be supplied under the interconnection agreement.
Response: GO’s applicability in this standard is not confined to just the ownership of breakers. Generating resources along with transmission system components and topology are significant drivers to system stability and dynamic behavior. Dynamic behavior is captured best through dynamic disturbance data rather than fault or sequence of events data. **By connecting to the system a generator contributes to System dynamic behavior.**		

Organization	Yes or No	Question 3 Comment
The providers of the data are not necessarily the sole beneficiaries of the data. The requirements in the standard that apply to GO's are limited to the applications where GO's have to provide data for wide-area disturbance analysis. System dynamic behavior is affected by individual generating unit responses.		
Northern California Power Agency	No	WECC has a Synchrophasor program. Why would not the RE or the appropriate RC identify the areas where this equipment is located and continue with the existing program?
Response: The standard addresses "what" data must be captured, not "how" it is captured. The RC has the responsibility in the Western Interconnection for Element selection for DDR data. It is expected that the WECC WISP installations will meet many of the sub-Part requirements.		
ReliabilityFirst	No	Applicability - ReliabilityFirst understands the rationale behind differentiating the Responsible Entity per Interconnection, but does not agree with ERCOT still stating "Planning Coordinator or Reliability Coordinator". ERCOT is both the Planning Coordinator and Reliability Coordinator so the DMSDT needs to decide which function in ERCOT will be responsible for determining DDRs to avoid any future confusion for monitoring compliance.
Response: The DMSDT was given information that in ERCOT the use of "Planning Coordinator or Reliability Coordinator" was appropriate because depending on where in ERCOT you were, either entity could be applicable.		
Colorado Springs Utilities	No	
MRO NSRF	Yes	Please see question 7.
Response: Refer to the Question 7 response.		

Organization	Yes or No	Question 3 Comment
SPP Standards Review Group	Yes	We thank the DMSDT for deleting the Reliability Coordinator as an Applicable Entity in the Eastern Interconnection.
Response: Thank you for your comment.		
Arizona Public Service Company	Yes	
Bureau of Reclamation	Yes	
Corporate Compliance/Engineering	Yes	
Dominion	Yes	
Duke Energy	Yes	
El Paso Electric	Yes	
Hydro One Networks Inc.	Yes	
JEA	Yes	
Nebraska Public Power District (NPPD)	Yes	
New York Power Authority	Yes	

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	Yes	
Pepco Holdings Inc & Affiliates	Yes	
Reason International, Inc.	Yes	
SERC Protection and Controls Subcommittee	Yes	
Southern Company	Yes	
Tacoma Power	Yes	
Tennessee Valley Authority	Yes	
Western Area Power Administration	Yes	
AESI Acumen Engineered Solutions International Inc.	Yes	
American Electric Power	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 3 Comment
CenterPoint Energy Houston Electric	Yes	
City of Tallahassee	Yes	
City of Tallahassee (TAL)	Yes	
Dynegy	Yes	
Edison Mission Marketing & Trading Inc.	Yes	
Entergy Services, Inc.	Yes	
Exelon Companies	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Ingleside Cogeneration LP	Yes	
ITC	Yes	
Kansas City Power & Light	Yes	

Organization	Yes or No	Question 3 Comment
LCRA Transmission Services Corporation	Yes	
Lower Colorado River Authority	Yes	
Luminant Generation Company LLC	Yes	
Manitoba Hydro	Yes	
N/A	Yes	
Oncor Electric Delivery	Yes	
PJM Interconnection	Yes	
Public Service Enterprise Group	Yes	
Texas Reliability Entity	Yes	
Wisconsin Electric Power Company	Yes	
Xcel Energy		We believe the "Responsible Entity" should be consistent across the Interconnections. We recommend changing this to be the Reliability Coordinator for all Interconnections.

Organization	Yes or No	Question 3 Comment
Response: The DMSDT used the appropriate entity for each Interconnection based on how they perform the required functions.		

4. **Do you agree with the Elements requiring Dynamic Disturbance Recording listed in Requirement R6? If not, please provide technical justification.**

Summary Consideration: The thrust of the comments received was that Requirement R6 (Requirement R6 is Requirement R5 in the latest draft of the Standard) demanded DDR data capture on an excessive number of BES Elements. The DMSDT revised Requirement R6 (now Requirement R5) to address these comments by:

- **Instead of monitoring all Elements of IROLs, monitor one or more**
- **Instead of monitoring all Elements of permanent Flowgates and transmission interfaces, monitor "Any one BES Element associated with major transmission interfaces…"**

The Parts/sub-Parts of what is now Requirement R5 have been re-arranged for clarity.

Organization	Yes or No	Question 4 Comment
ACES Standards Collaborators	No	We believe that Requirement R6 could be consolidated with other requirements and the detailed sub-requirements could be moved to an appendix. This would be more appropriate to model this standard like PRC-023-2, where the appendix provides important details but does not subject registered entities to violations for every sub-requirement.
Response: Requirement R6 has been combined with R7 into what is now R5. In response to numerous comments received, the DMSDT revised R6 (now R5) to clarify which Elements are required (identified in the numbered Parts of the requirement) and which ones are to be considered (bulleted items).		
Bonneville Power Administration	No	a) BPA feels there should not be a requirement to monitor all elements of a path/interface/IROL when three of five lines can supply enough understanding (used in conjunction with other DME); and

Organization	Yes or No	Question 4 Comment
		b) The IROL should be determined by Planning Criteria, not by a dynamic/ever-changing IROL.
Response: Based on numerous comments, the DMSDT has changed the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts were updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one or more (as specified by the RC or PC) Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).		
El Paso Electric	No	No. Requirement 6 contains too many potential DDR locations. DMSDT should provide clarity between requiring one DDR per system, requirement 6.1.2, versus requirements 6.1.5, 6.1.6 and 6.1.7. The criteria for placement need to be clarified.
Response: Based on numerous comments, the DMSDT has changed the format of the requirement (Requirement R6 is now R5) to clarify the data requirements which will reduce the potential number of locations that are to be identified.		
Florida Municipal Power Agency	No	Please see response to question 7.
Response: Please see the DMSDT response to Question 7.		
Hydro One Networks Inc.	No	1. R6.1.4, first bullet - Requiring monitoring of all "Flowgates" on the Eastern Interconnection seems arbitrary and diminishes the role of those with the best understanding of the nature of their system to determine the appropriate locations for DDRs. The guideline for R6 included in the draft fails to explain why all flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the

Organization	Yes or No	Question 4 Comment
		maximum precontingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with the requirement R6.1.3.2 since there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. 2. Requirement R6.1.5 - This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities 3. Requirement R6.1.6 - The guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLs) should be monitored. The NERC lists including all elements associated with IROLs are very extensive. This requirement will increase the number of the DDRs need to be installed exponentially.

Response: Based on numerous comments, the DMSDT has revised Requirement R6 (now R5) in the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts have been revised according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).

The list of Elements for HVDC includes both ends of HDVC terminals; the data monitoring requirement for each end is based on the ownership of their respective Elements. The case described is included in the draft standard already; responsibility is based on ownership of Elements for DDR.

The Guideline has been revised for the R6 (Requirement is now R5) sub-Parts, and explanations for including each type of Element for DDR data monitoring.

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee	No	R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but Part 6.1.1 and 6.1.2 are not criteria for “Elements”, but rather, they are criteria based on demand size and footprint. It would clarify for compliance if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., Pats 6.1.1 and 6.1.2), and one for the location/element (Parts 6.1.3 to 6.1.6). Also, M6 for R6 states that the responsible entity must “accurately” identify elements requiring DDR per numerous sub-requirements under R.6.1. and measures degrees of compliance against an identified set of points as specified per 6.1.4. R.6.2. requires that entities, at a minimum, perform a new assessment for DDR locations every 5 years. When there are elements added to the Interconnections or long-term system reconfigurations that take a DDR(s) out of service or renders them incapable of recording the required data, should that be a trigger for a reassessment?
Response: In response to the comments received, the DMSDT has Revised Requirement R6 (now R5) for clarity. **The 5 year maximum reassessment period for the list of Elements requiring DDR data is used to capture any major changes to the system during that period. This is similar to what is required for SER, and FR (R1--R1 and R2 have been combined into what is now R1). Requirement R14 (Requirement number is now R12) should be followed If DDR equipment is removed from service such that it is out of service or incapable of recording the required data.**		
MRO NSRF	No	Note that R6 clearly states where DDRs are required where the intent of this Standard was for “data” and not devices. The DMSDT has presented mixed signals to the industry, please clarify.

Organization	Yes or No	Question 4 Comment
		In R6.1.2., it states that at least one DDR location in each Responsible Entity's footprint. It is not clear if this means the Responsible Entities listed in R6 or the Responsible Entities listed in the Applicability Section 4. Does the Planning Coordinator or Reliability Coordinator, (as applicable) identify BES Elements for which DDR is required in the footprint of each Transmission Owner and Generator Owner or in their own respective footprints? R6.1.2. should be clarified to read "Each Planning Coordinator or Reliability Coordinator, (as applicable) is required to have at least one DDR in their footprint."
Response: The focus of this standard is on the data, not equipment. The requirements were revised to reflect the necessity to monitor data, not prescribe how that data is collected. **"Responsible Entity" is a defined term for this standard PRC-002-2, and refers to the Planning Coordinator or Reliability Coordinator (as applicable for each Interconnection as per the Applicability Section of the standard). The minimum DDR criteria have been updated as (R5 is now R6):** **5.2 The elements shall include a minimum of :** **5.2.1. One BES Element.** **5.2.2. One additional BES Element for each additional 3,000 MW of its historical peak system Demand.**		
Nebraska Public Power District (NPPD)	No	For clarification, "A minimum of one DDR location per 3,000 MW of the Responsible Entity's historical peak system Demand, inclusive of Requirement R6, Part 6.1, Sub-parts 6.1.2 - 6.1.7" means that for a peak demand of 3030MW a Responsible Entity must have at least two DDRs on its system and this requirement is satisfied if two DDRs are already on the system due to the other sub parts in R6?

Organization	Yes or No	Question 4 Comment
		Has or should it be confirmed the RC or PCs have a clear understanding and listing of “permanent Flowgates” and locations necessary to monitor all Elements associated with IROLs? They may need to confirm they are using similar or same terminology.
Response: In response to numerous comments, the DMSDT has Revised Requirement R6 (now R5) for clarity. **The Standard DMSDT (DMSDT) has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of “major transmission interfaces” has on Transmission Owners. Sub-Parts have been revised according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. “Major transmission interfaces” are also included but at a reduced level. Only one Element of these interfaces is required and “major” is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring). Wording has been added to the Rationale Box for what is now R5 for further clarification.**		
New York Power Authority	No	R6.1.6 - This requirement could lead to unnecessary installation of DDRs in non-integral substations.
Response: Interconnection Reliability Operating Limits (IROLs) are a subset of System Operating Limits (SOLs) that if violated could lead to instability, uncontrolled separation, or initiate cascading outages (as defined in FAC-010-1). Due to the severity of these violations and the possibility for large-scale outages or cascading, these IROLs should be monitored for disturbance monitoring, and capturing and recreating system disturbances from a wide-area. However, the draft standard has been updated such that only one or more Element(s) of each IROL (as specified by the RC or PC) is required, rather than all Elements of each IROL.		
Northeast Power Coordinating Council	No	Requirement R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but sub-Parts 6.1.1 and 6.1.2 are not criteria for “Elements”, but rather, they are criteria based on demand size and footprint.

Organization	Yes or No	Question 4 Comment
		It would be helpful if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., sub-Parts 6.1.1 and 6.1.2), and one for the location/element (sub-Parts 6.1.3 to 6.1.6). Suggest moving the minimum quantities in sub-Parts 6.1.1 (minimum 1 DDR per 3000 MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the requirements for sub-Parts 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc...), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable requirements, and state that additional DDR locations are only needed if fulfilling the first 5 do not meet the two extra minimum quantities requirements. Sub-Part 6.1.3--Needs to be clarified to make it understood how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples would be helpful. Sub-Part 6.1.4, first bullet - Requiring monitoring of all “Flowgates” on the Eastern Interconnection seems arbitrary and diminishes the role of those with the best understanding of the nature of their system to determine the appropriate locations for DDRs. If “Flowgate” monitoring is required, this item should include a link to the official list of NERC Flowgates so that the “Responsible Entity” knows where they need to install DDRs. For example, the NY-NE interface is one of the official NERC Flowgates, which means that entities will need a DDR at each of eight stations that interconnect with New York; while entities on the other end of the interconnection in NE will need to do the same. Regarding “monitor all Elements of: all permanent Flowgates”. If a Flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every

Organization	Yes or No	Question 4 Comment
		transformer need to be monitored (low side or high side side)? Please show some typical examples. The guideline for R6 included in the draft fails to explain why all Flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the maximum pre-contingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with sub-Part 6.1.3.2 because there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. Clarify that DDR is for “all permanent Flowgates” ONLY if the Flowgates are BES Elements. Sub-Part 6.1.5 - this will require the installation of DDRs at HVDC facilities that are smaller than the generator requirement listed in sub-Part 6.1.3 (500 MW). This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities. Sub-Part 6.1.6 - This requirement could lead to installation of DDRs at many substations to just capture one flow that is part of an IROL. Also, DDR data is of little value for IROLs that are thermal in nature. Sub-Part 6.1.6/Guideline - The Guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLs) should be monitored.

Organization	Yes or No	Question 4 Comment
		The NERC lists including all elements associated with IROLs are very extensive. This requirement will dramatically increase the number of the DDRs need to be installed. This could cause too excessive burden on some TOs. Also, there is nothing to limit the burden which can be placed on the TO by a Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable). Depending on the impact, a 3-year implementation plan might not be achievable.
Independent Electricity System Operator	No	R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but Part 6.1.1 and 6.1.2 are not criteria for “Elements”, but rather, they are criteria based on demand size and footprint. It would be helpful if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., Pats 6.1.1 and 6.1.2), and one for the location/element (Parts 6.1.3 to 6.1.6). Requirement R6.1.4 - The guideline for R6 included in the draft fails to explain why all flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the maximum precontingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with the requirement R6.1.3.2 since there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. Requirement R6.1.5 - This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities.

Organization	Yes or No	Question 4 Comment
		Requirement R6.1.6 - The guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLs) should be monitored. The NERC lists including all elements associated with IROLs are very extensive. This requirement will increase the number of the DDRs need to be installed exponentially.

Response: In response to numerous comments, the Standard DMSDT (DMSDT) has revised R6 (now R5) for clarity.

The sub-Part for generating resources was also clarified as well as the Guideline document. Wording was added to the Rationale Box.

Based on numerous comments, the Standard DMSDT (DMSDT) has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).

The list of Elements for HVDC includes both ends of HDVC terminals; the data monitoring requirement for each end is based on the ownership of their respective Elements. The case described is included in the draft standard already; responsibility is based on ownership of Elements for DDR. Interconnection Reliability Operating Limits (IROLs) are a subset of System Operating Limits (SOLs) that if violated could lead to instability, uncontrolled separation, or initiate cascading outages (as defined in FAC-010-1). Due to the severity of these violations and the possibility for large-scale outages or cascading, these IROLs should be monitored for disturbance monitoring, and capturing and recreating system disturbances from a wide-area. However, the draft standard has been updated such that only one Element of each IROL is required, rather than all Elements of each IROL.

The DMSDT has revised Requirement R6 (now R5) to provide more clarity. Major transmission interface criteria have been developed in what is now sub-Part 5.1.2.

Organization	Yes or No	Question 4 Comment
Reason International, Inc.	No	Power swings are one of the most common and dangerous long-term disturbance events. They occur due to inadequate power flow conditions in a variety of states of the BES. These dangerous states may be reached through unforeseeable manual maneuvers or inadvertent automatic maneuvers during operation, as those occurring during an fault. Power swings may evolve to a system-wide failure, due to voltage dips, under- over-frequency, etc. To correct evaluate this situation it is necessary to compute the system power. Therefore, it's also necessary to monitor currents as well as voltages.
Response: The DMSDT agrees that currents should be monitored along with voltages; this is already accounted for in Requirements R8 (Requirement is now R6) and R9 (Requirement is now R7).		
SERC Protection and Controls Subcommittee	No	1. Our industry experience is that disturbance events for which DDR information and analysis is needed are extremely rare (perhaps one per decade; in fact we've not yet experienced such an event). We believe that the proposed R6.1.4 alone would increase our number of NERC required DDR for one of our members at least thirty-fold. The DMSDT has not provided technical justification for this proposed significant increase. For this member, the other parts of 6.1 may well triple their NERC required DDRs. We ask the DMSDT to consider a reasonable approach and omit Requirement 6.1.4 and reconsider it in the five-year review of this standard if NERC-wide experience in the meantime warrants it. Perhaps this is a regional issue and some regions have a stronger need; if so, we suggest they draft a regional standard. 2. A quick analysis of another of our members identified 12 generating plant locations (R6.1.3), 18 flowgates (R6.1.4) at 12 locations and one IROL (R6.1.6) location where we own Elements. Presently we are required by SERC to have DDR at 6 locations.

Organization	Yes or No	Question 4 Comment
		This results in the entity possibly needing DDR at 19 additional locations, with a total of 25! Was there any effort, as was suggested in the Atlanta DMSDT open forum meeting, for a data request of the REs to assess how many DDRs (Elements) would be need to be monitored? If so where is this information? If this was not done, it must be a part of the cost impact effort. 3. Clarity is needed under Requirement 6.1.3 to understand how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples will be most helpful. 4. Clarity is needed in Requirement 6.1.4 (if it is retained) when you refer to "monitor all Elements of: all permanent flowgates". If a flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every transformer need to be monitored (lowside or highside side)? Please show some typical examples. 5. Under Requirement 6.1, it may be better to move the minimum quantities Requirements 6.1.1 (minimum 1 DDR per 3000MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the Requirements for 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc...), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable Requirements, and state that additional DDR locations are only needed if fulfilling the first 5 Requirements does not meet the two extra minimum quantities Requirements.

Response: Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according

Organization	Yes or No	Question 4 Comment
to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. “Major transmission interfaces” are also included but at a reduced level. Only one Element of these interfaces is required and “major” is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring). **The sub-Part for generating resources has been clarified as well as the Guideline document to help provide clarity.** **Based on numerous comments, the DMSDT has revised R6 (now R5) for clarity.**		
Southern Company	No	a) In the Background section, the DMSDT explains the basis for the 500MW threshold; however, there is no explanation/ basis for the 300MW at locations over 1000MW. b) It is not clear in R9 whether the specification for signal measurements is on a generating unit basis or if the signals of interest are a per line basis aggregate at generating stations. Please more clearly specify if the signals of interest are individual unit measurements or plant total measurement (grouped by output circuit, plant total, etc.). This determination weighs heavily on the cost and method of implementation where new equipment must be installed. Example: (i.e. combined cycle plant (1075MW total) with units of 325, 325, 425 but only one transmission line)? c) In reference to the R6.1.4: The monitoring of all elements of a permanent flowgate should be changed to only the major elements or perhaps those that contribute more than 20%. In some cases multiple lines of 500, 230, and 115kV may be involved but the lower voltage lines may only contribute 5-10% of the total capacity. Having to install DDR capability at these multiple locations is overly burdensome and does not enhance the overall goal of this Standard.

Organization	Yes or No	Question 4 Comment
Response: The DMSDT has included the 300 MVA threshold for generating resources at locations with a gross/aggregate nameplate rating of 1000 MVA to capture large multi-unit disturbances that could occur due to non-electrical related contingencies such as plant failures. NERC Event Analysis subject matter experts have identified plant or multi-unit generation trips that could pose a risk to grid stability. DDR is required only for "large" (300 MVA) units at plants greater than 1000 MVA to capture their response and potential tripping and risk to under-frequency events. A revision to the guidelines was made to clarify the 300 MVA threshold. **The TO or GO is required to provide the necessary DDR data to meet the requirements set forth in Requirement R6 (Requirement R6 is now R5). 500 MVA individual units or 300 MVA units at plants 1000 MVA or greater need to be monitored.** **Based on numerous comments, DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).**		
SPP Standards Review Group	No	Requirement R6.1.3.2 requires DDR for all generating units greater than 300 MVA at a plant/facility with an aggregate nameplate rating equal to or greater than 1000 MVA. Does this apply in situations where the generating units may be connected at different voltage levels within the plant/facility? Especially those which may not even be tied together within the plant/facility? YES Requirement R6.1.4 requires DDR for all permanent Flowgates within the Eastern Interconnection. We believe this requirement is troublesome for several reasons. First, Flowgates can be added on the fly in Real-time. Although these Flowgates are at that time

Organization	Yes or No	Question 4 Comment
		temporary, they can become permanent at the end of the month in which they were created in the Book of Flowgates. Thus a Transmission Owner would then be responsible for having DDR equipment on that Flowgate within less than 30 days. This is an unreasonable request. Additionally, most Flowgates are thermally limited and not all of them represent facilities which have a significant impact on the BES. They may have been created to address localized loading issues. As such, requiring these facilities to be monitored by DDR equipment is excessive and does not contribute significantly to the reliability of the BES. On the other hand, there may be other Flowgates which do consist of or represent facilities which can have a tremendous impact on the BES. Some of these Flowgates are there specifically to address voltage stability and dynamic system stability issues. These facilities need to be monitored by DDR equipment. The difficulty becomes determining which Flowgates fit the latter category. The DMSDT needs to put some effort into determining the criteria to use in deciding which Flowgates are worthy of DDR monitoring.

Response: The DMSDT has included the 300 MVA threshold for generating resources at locations with a gross/aggregate nameplate rating of 1000 MVA to capture large multi-unit disturbances that could occur due to non-electrical related contingencies such as plant failures. NERC Event Analysis subject matter experts have identified plant or multi-unit generation trips that could pose a risk to grid stability. DDR is required only for "large" (300 MVA) units at plants greater than 1000 MVA to capture their response to system disturbances.

The sub-Part for generating resources is also being clarified as well as the Guideline document to help provide clarity and examples. (This is used for generator aggregation.)

A revision to the guidelines was made to clarify the 300 MVA threshold.

Organization	Yes or No	Question 4 Comment
Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).		
Tennessee Valley Authority	No	We respectfully request that a methodology similar to the one that was used in R1 is deployed in this requirement in order to determine an adequate percentage of flowgates needed for visibility of faults.
Response: Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).		
Western Area Power Administration	No	DDR installations have been resource intensive and problematic to install and to place on-line. Section 6 opens the door for quite a number of DDR deployments. Section 6.1.4 requires the monitoring of all Elements of major transfer paths on the Western Interconnection. Utilities in the Western Interconnection have already participated in WECC's WISP program and have installed and commissioned DDR's as required. DDR deployment per WISP should be considered sufficient in the WECC footprint.

Organization	Yes or No	Question 4 Comment
Response: Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring). **Phasor Measurement Units (PMUs) and synchrophasor data are a subset of DDR, streaming high resolution data in real-time. The PMUs installed under the WECC WISP likely will meet many of the sub-Parts set forth in this standard; however, additional installations are required to capture wide-area system response to large outages such as cascading or instability.**		
Ameren	No	(1) In conjunction with our Planning Coordinator we have voluntarily installed over 30 PMUs which was a significant effort and resource commitment over the last 3 years. Even though they have not yet been needed for disturbance analysis, some operating visualization tools are being used and we have reviewed some minor perturbations. However, if we would still need to have a PMU covering every generator with 500 MW or greater as in 6.1.3.1, as well as all permanent flowgates, as covered in 6.1.4, that would require us to add many more PMUs to the system. We believe this would be burdensome, given the effort already undertaken over the last 3 years to get to where we presently are. We respectfully disagree with the DMSDT's brief justification in the Rationale for R6.
Response: Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is		

Organization	Yes or No	Question 4 Comment
defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring). **DDR data requirements for generating resources of the size threshold established requires a relatively low number of generating units monitored while capturing a large amount of the total MVA capacity on the system. This is based on the analysis performed by the DMSDT using the NERC GADS data.**		
American Electric Power	No	This listing appears far too prescriptive by going beyond the "what's" and specifying the "how's". In the application of R6, the Responsible Entity should consider existing DDR installations when determining where to require DDR. There may be existing installations that can satisfy the R6 criteria. At a minimum, it might be beneficial to add such considerations to the "Guideline for Requirement R6" section. It is unclear whether DDR is required on all generating resources or only some generating resources that meet the requirements of R6.1.3.1 and R6.1.3.2. We suggest changing the title of Section 6.1.3 to "All generating resources with:" to be consistent with the other sections.
Response: The DMSDT agrees that the Responsible Entity should consider existing DDR installations when determining the Elements requiring DDR data. (Requirement R6 in the posted PRC-002-2 draft has been renumbered to R5, and the sub-Parts rearranged). For example, generating resources, major transmission interfaces, IROLs, and voltage sensitive areas can be measured from multiple points. Note that data can either be directly measured or derived. The DMSDT does not believe that 'all' is needed in sub-Part 6.1.3 because sub-Parts 6.1.3.1 and 6.1.3.2 are clear.		
CenterPoint Energy Houston Electric	No	CenterPoint Energy understands the potential usefulness of dynamic data for event analysis and supports the collection of dynamic data for event analysis as a Best Practice.

Organization	Yes or No	Question 4 Comment
		However, the Company's experience has been that sufficient data for event analysis is available from existing fault recording devices and therefore is strongly opposed to inclusion of a requirement to provide dynamic data. The only way to provide dynamic data is through a dynamic recording device. If an entity does not currently have any dynamic recording devices installed on its system then the entity has little choice but to spend capital in order to acquire and install these devices to comply with the Requirement. CenterPoint Energy does not believe the enabling legislation allows for Reliability Standards to require the expenditure of capital funds. While the DMSDT contends the requirement is only for dynamic data, not the installation of dynamic recording devices, and an entity is free to determine how it will comply, CenterPoint Energy finds this argument disingenuous.CenterPoint Energy strongly recommends the deletion of this requirement. The Company cannot support any draft Standard that contains such a requirement.
Response: The DMSDT understands that in the case of DDR specific devices are needed to provide the data. In certain cases a fault recorder that is equipped to do provide DDR can be used. The standard is not concerned with the "how", but with "what" data is captured. The DMSDT's objective was to provide the industry as much flexibility as possible where the equipment was concerned to capture data. For a widespread slowly evolving event dynamic disturbance data is necessary to understand its development. **In response to comments, the DMSDT has revised Requirement R6 (R6 is now R5) to provide more specificity regarding data requirements.**		
Dairyland Power Cooperative (DPC)	No	Please provide the technical justification for Requirement R6.1.1.

Organization	Yes or No	Question 4 Comment
Response: Part 6.1.1 (Part is now 5.2.2) is included because there may be some areas of the system where a PC or RC does not have sufficient DDR coverage based on its peak system Demand size. If the other sub-Parts do not provide sufficient coverage, then additional unique locations should be selected such that wide-area coverage is attained.		
Dynegy	No	1.) Regional Standard PRC-002-NPCC-01 which recently became effective conflicts with PRC-002-2. There is no bright line 500 MVA criteria for GOs to install DDR in the NPCC Regional Standard which instead allows the Reliability Coordinator to make the call. Also, it is not clear from R6 if the GO is supposed to wait for notification from the RC to install DDR or if the GO should go ahead and install DDR at units >500 MVA on their own. 2.) It's recognized that the DMSDT researched the 500 MVA cutoff point to cover what was felt to be an appropriate percentage of US generating assets. Based on comparisons with other Regional Criteria and Standards, this number seems low - some use a number of 1000 MVA. A compromise cutoff of 750 MVA is suggested. 3.) PRC-002-NPCC-01 requires installation of SOER and FR at generating units while PRC-002-2 specifically states SOER and FR are not required at generating units. Some GOs have spent considerable capital dollars to comply with a new NPCC Regional Standard, only to have a new conflicting continent wide Standard proposed.
Response: In response to comments, the DMSDT has revised Requirement R6 (now R5) to provide more specificity regarding data requirements. A Generator Owner with an individual unit greater than or equal to 500 MVA is free to ensure that the data is available prior to notification. **(1) PRC-002-2 is a continent-wide standard; regional standards such as PRC-002-NPCC-01 may be more prescriptive than this draft standard. However, the DMSDT has included the 300 MVA threshold for generating resources at locations with a gross/aggregate**		

Organization	Yes or No	Question 4 Comment
nameplate rating of 1000 MVA to capture large multi-unit disturbances that could occur due to non-electrical related contingencies such as plant failures. NERC Event Analysis subject matter experts have identified plant or multi-unit generation trips that could pose a risk to grid stability. **(2) The DMSDT believes the 750 MVA cut off threshold is too high to provide sufficient data from generating units. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47% of the generating capacity in the NERC footprint while only requiring DDR coverage on about 12.5% of the generating units.** **(3) The regional standards may dictate stricter requirements pertaining to particular recording requirements. This continent-wide standard identifies the effectiveness of DDR data to capture generating resources and their longer-term response to system disturbances that are captured by DDR. This standard focuses on capturing DDR data while minimizing the impact of sequence of events and fault recording data requirements for Generator Owners.**		
Entergy Services, Inc.	No	We believe the proposed DDR installation criteria will require an excessive number of installations, has not been technically justified by the DMSDT for the increase in DDR installations which will be required, and will be unnecessarily burdensome to the industry. Industry experience shows that disturbance events for which DDR information and analysis is needed are very rare, and we believe the R61.1 criteria puts us closer to what should be a target number of installations rather than a minimum number.
Response: Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).		

Organization	Yes or No	Question 4 Comment
Widespread outages are rare, but historical events have illustrated the need for time synchronized dynamic data from a wide-area perspective. Capturing wide-area system behavior prior to and immediately following a fault or contingency condition enables recreation of sequence of events during the cascading or outage. The sub-Parts put forth in this standard identify Elements for which time synchronized dynamic recording data provide valuable information for understanding and recreating the system's response.		
Exelon Companies	No	We believe the DMSDT has done a good job of trying to focus on the important BES elements that should require Dynamic Disturbance Recording. Requiring DDR for the most important BES elements rather than all BES elements at a certain station is technically sound and a major improvement over some attempts at past criteria to determine which elements should require DDR. We concerend however that about the specificty for determination as to the number and location of where DDR will be required per this requirement. The requirment may result in an unnecessary number of installations. We urge the DMSDT to provide for the PC to determine the number and location of the devices. Addtionally, use of the NERC book of flowgates may not support again the necessary data required because every line in a Flowgate or IROL, IROLs is not always dynamic limited.
Response: Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).		

Organization	Yes or No	Question 4 Comment
Ingleside Cogeneration LP	No	Unlike the MVA thresholds applied in R1, ICLP does not believe that the 1000 MVA threshold for generation facilities (R6.1.3.2) is consistent with other NERC criticality criteria. In addition, from the perspective of a Cogeneration facility, full nameplate capacity is normally not fully available to the Bulk Electric System. Therefore, either the threshold should be raised to 1500 MVA or should be revised to specify that the 1000 MVA threshold refers to "aggregate nameplate capacity available to the BES".
Response: The DMSDT has included the 300 MVA threshold for generating resources at locations with a gross/aggregate nameplate rating of 1000 MVA to capture large multi-unit disturbances that could occur due to non-electrical related contingencies such as plant failures. NERC Event Analysis subject matter experts have identified plant or multi-unit generation trips that could pose a risk to grid stability. DDR is required only for "large" (300 MVA) units at plants greater than 1000 MVA to capture their response and potential tripping and risk to underfrequency events. The 1000 MVA plant/aggregate nameplate rating captures the generating facilities of interest for DDR while 1500 MVA would exclude large power generating facilities. Examples of typical or likely configurations have been included in the Guidelines document to help clarify.		
ISO New England Inc.	No	Comment on R6 - The standard should not use the term "Responsible Entity" but should only refer to specific NERC entities like TO, GO, RC, etc. Comment on R6.1.4 -Requiring monitoring of all Elements of "Flowgates" on the Eastern Interconnection seems arbitrary and may miss important locations for DDRs, especially for areas that do not use flowgates. If "Flowgate" monitoring is required, this item should include a link to the official list of NERC Flowgates so that the "Responsible Entity" knows where they need to install DDRs. This requirement will also lead to installation of equipment that provides practically no value to the Purpose of this standard. For example, the NY-NE interface is one of the official NERC Flowgates, which means that ISO-NE will need a DDR at each of eight stations that interconnect with New York; NYISO will need to do the same and lead to the

Organization	Yes or No	Question 4 Comment
		installation of unnecessary, redundant equipment. DDR location requirements for ERCOT, Hydro-Quebec, and the Western Interconnection do not define major transmission interfaces or major transfer paths, allowing for arbitrary interpretation. Also, for the Western Interconnection, responsibility is placed on the "Regional Entity" and not a "Responsible Entity" like the Reliability Coordinator or Planning Coordinator. Comment on R6.1.5 - this will require Reliability or Planning Coordinators to call for the installation of DDRs at HVDC facilities that are smaller than the generator requirement listed in R6.1.3 (500 MW). If this requirement is retained, it should be specify "... HVDC facilities greater than 500 MW..." Comment on R6.1.6 - This requirement could lead to installation of DDRs at many, many substations in New England just to capture one flow or voltage that is part of an IROL. Also, DDR data is of little value for IROLs that are thermal in nature. General comment on 6.1.3 through 6.1.7: The level of detail specified in these items eliminates the role of the RC/PC who are best able to determine appropriate locations for DDRs. This requirement should recommend locations and not attempt to precisely specify where DDRs should be installed. These requirements could be rephrases as follows: "The RC/PC shall specify DDR locations that serve the Purpose of this standard (To have adequate data available to facilitate event analysis of BES disturbances). The RC/PC should consider specifying locations that include generators and HVDC facilities greater than 500 MW, major transmission interfaces, transfer paths, flowgates, voltage sensitive areas..."
Response: The Responsible Entity is used in this standard to refer to either the Planning Coordinator or Reliability Coordinator (NERC registered entities) based on Interconnection. This is detailed in the Applicability Section 4 of the Standard. This helps simplify the requirement verbiage and application to each Interconnection.		

Organization	Yes or No	Question 4 Comment
Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring). **The Regional Entity is used in the Western Interconnection for determining the "major transmission interfaces" because they have a well-defined list of interfaces (such as the WECC Path Rating Catalog) that have been studied and considered "major". Others such as ERCOT and Hydro-Quebec will have the Planning Coordinator or Reliability Coordinator develop a similar list of interfaces as described above, with recommendation from a guideline document provided.** **The DMSDT believes that all HVDC should be included and Part 6.1.5 (revised to be Part 5.1.3) has been revised to reflect this. The DMSDT notes that each TO is only responsible for DDR data for the elements that they own.**		
ITC	No	6.1.4 for Eastern Interconnection "permanent Flowgates" rather than using a blanket approach to require DDR on all defined Flowgates, they should be selectively placed on those Flowgates that have a chronic congestion history. The DDRs should be placed on the defined monitored element(s) of permanent flowgates that exhibit a history of chronic congestion.
Response: Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).		

Organization	Yes or No	Question 4 Comment
Kansas City Power & Light	No	The inclusion of all permanent flowgates is our objection. This requirement will result in the inclusion of monitoring points that are not necessarily critical to the BES. The approach of the Western Interconnection to include all major transfer paths as defined by the Regional Entity seems to be a more logical approach.
Response: Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).		
LCRA Transmission Services Corporation	No	Not cost-effective based on cost of improvements vs. benefit. TO installations adequately address requirement. VRFs are all in the "Lower" range which supports the fact that the requirements are unnecessary. Reference recent actions related to Paragraph 81.
Lower Colorado River Authority	No	Not cost-effective based on cost of improvements vs. benefit. TO installations adequately address requirement. VRFs are all in the "Lower" range which supports the fact that the requirements are unnecessary. Reference recent actions related to Paragraph 81.
Response: The DMSDT has considered cost effectiveness compared with reliability benefit, and the CEAP is further considering this issue. The DMSDT acknowledges the use of "Lower" VRFs and notes the criteria for a "Lower VRF": 1) "if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system", 2) if violated, would not hinder the "ability to effectively monitor and control the bulk electric system", and 3) is a "requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to		

Organization	Yes or No	Question 4 Comment
adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system." This requirement meets the guidelines for a Lower VRF.		
Liberty Electric Power LLC	No	The standard is too prescriptive for DDR. The TO should select the sites, install and maintain the DDR they properly need to analyze a disturbance on their system. The standard should simply require "DDR shall be installed as necessary to analyze a fault on the TO's system". Violations of the standard would only occur if a fault is unable to be analyzed due to equipment not being installed (not due to failure or outage of installed equipment).
Response: The DMSDT has considered cost effectiveness compared with reliability benefit, and the CEAP is further considering this issue. **DDR is not used to analyze a fault on a TO's system, and is intentionally not used during unbalanced fault system conditions due to the RMS representation of waveform data. Fault Recording is used during fault conditions when the system is in an unbalanced operating condition rather than DDR data. The use of language such as "as necessary" is ambiguous and unenforceable. From a wide-area perspective, the Responsible Entity (RC or PC) has the tools and knowledge to specify DDR data locations.**		
N/A	No	1. Requirement R6.1.5 - Consideration should be given to address the case when the ends of HVDC terminals (back-to-back or each terminal of a DC circuit) on the AC portion of the converter are owned by different entities 2. Requirement R6.1.6 - Justification should be provided on the technical justification for all Elements associated with IROLs to be monitored. The NERC lists including all elements associated with IROLs are very extensive, thus significantly increasing the number of the DDRs that need to be installed.
Response: (1) The DMSDT believes that all HVDC should be included and has revised Part 6.1.5 (now Part 5.1.3) to reflect this. The DMSDT notes that each TO is only responsible for DDR data for the elements that they own.		

Organization	Yes or No	Question 4 Comment
(2) Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).		
Oncor Electric Delivery	No	The R6.1 sub-requirement describes minimum locations. There are no limitations on the DDR requirements written into the standard language. This could potentially lead to the Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) overburdening the TO/GO with the volume of included locations. The language in R1 provides a "20%" audit curtailment for the FR/SOER but there is no similar language for the DDRs in R6.
Response: In terms of checks and balances for the Responsible Entity, the intent of the standard is not to implement unnecessary or excessive DDR for collecting wide-area data; rather, the intent is to capture sufficient data for the standard's purpose. The Responsible Entity should not impose excessive DDR data requirements on its respective TOs and GOs. To accommodate this concern, a list of "major transmission interface" criteria has been developed and put in Part 5.1.2 for selecting these "major" interfaces, attempting to minimize ambiguity and excessive requirements.		
PJM Interconnection	No	PJM is concerned about the specificity for determination as to the number and location of where DDR will be required per this requirement. Our concerns include the number of DDRs may be sufficient for monitoring but not for data validation. Monitoring lines may not provide the data to adequately perform disturbance analysis. Additionally, the requirement may result in an unnecessary number of installations.

Organization	Yes or No	Question 4 Comment
		We urge the DMSDT to provide for the PC to determine the number and location of the devices. Additionally, use of the NERC book of flowgates may not support again the necessary data required because every line in a Flowgate or IROL, IROLs is not always dynamic limited.
Response: The DMSDT has considered locations and Elements for DDR and chosen selected Elements for DDR since DDR may not be needed for all Elements at a particular location. The DMSDT agrees that the number of DDR for this standard is sufficient for monitoring and disturbance analysis; however, the number may be insufficient for model validation purposes. Disturbance monitoring for event analysis is the purpose of this standard with system and model validation an ancillary benefit. **For the Eastern Interconnection, the PC determines the Elements for which DDR data is required.** **Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).**		
ReliabilityFirst	No	Requirement R6, Part 6.1.3.2 - For Requirement R6, Part 6.1.3.2 ("Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA), does this mean only individual units which are greater than 300 MVA and part of plant need to have DDRs? If this is the case, it appears that a plant that has five 200 MVA units does not require DDRs. Is this the DMSDTs intent? ReliabilityFirst believes any plant/facility that has an aggregate nameplate greater than 1000 MVA, should have equipment capable of DDR.

Organization	Yes or No	Question 4 Comment
Response: **The 300 MVA capacity limit for individual units at large generating facilities with aggregate nameplate rating of 1000 MVA is used to capture only those "large" units at that plant and to mitigate the need for installing DDR equipment for relatively small generating units at a facility. The DMSDT and industry subject matter experts analyzed the NERC GADS data, and feel the 300 MVA lower MVA capacity limit is sufficient for capturing response of generating resources of interest.**		
Colorado Springs Utilities	No	
American Transmission Company, LLC	Yes	The criteria for selecting Elements requiring DDR in Requirement R6 are mostly acceptable. However, ATC recommends the consideration of the following wording changes: a. For R6 - Simplify the beginning with wording like, "Each Planning Coordinator or Reliability Coordinator (as applicable) shall . . ." b. For R6.1 - Specify more clearly that R6.1 is limited to BES Elements with wording like, "The BES Elements shall include the following:" c. For R6.1.1 - Make each sub requirement consistent with the parent R6.1 subject of "Elements" with wording like, "Elements at a minimum of one DDR location per . . ." d. For R6.1.2 - Make each sub requirement consistent with the parent R6.1 subject of "Elements" with wording like, "Elements at a minimum of one DDR location in . . ." e. For R6.1.3 - Add more clarity regarding the applicable Elements with wording like, "Elements at DDR locations, which interconnect the following generation resources to BES transmission buses:" f. For R6.1.4 - Make each sub item consistent with the parent R6.1 subject of "Elements" with wording like, "Elements necessary to monitor the following items:" g. For R6.1.4, bullet item 1 - Limit the scope of this item to only major permanent flowgates (similar to the other three bullets), rather than all permanent flowgates

Organization	Yes or No	Question 4 Comment
		(which generally includes all BES circuits), and allow the Planning Coordinators to define what "major" means with wording like, "Eastern Interconnection - all major permanent Flowgates as defined by the applicable Planning Coordinator."
Response: The wording and Part/sub-Part numbering in Requirement R6 (R6 and R7 have been combined into R5) in the latest revision of PRC-002-2 have been revised in response to comments received.		
Northern California Power Agency	Yes	Generally yes; however this should be consistent with WECC's continued synchrophasor program
Response: The WECC WISP installations can and should be considered when meeting the Requirement R6 (now R5) Element selection requirements.		
Texas Reliability Entity	Yes	(1) The DMSDT should clarify the meaning of "major transmission interfaces" in 6.1.4, as this is an undefined term that will lead to considerable debate about what a "major" interface is. (2) The DMSDT may also want to consider applying DDRs to Elements with a known angular stability issue or subsynchronous resonance issue that does not rise to the level of an IROL.
Response: Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring).		

Organization	Yes or No	Question 4 Comment
While subsynchronous resonance (SSR) and angular stability are not primary Parts/sub-Parts , it is expected that other DDR location requirements nearby could suffice for SSR purposes.		
Xcel Energy	Yes	We agree, however some clarity should be added: 1) In R6, mention is made of both Elements and locations for locating DDR. Is the intent to have the location be an entire substation, an entire bus, or a single Element? Or is that entirely at the discretion of the Responsible Entity? 2) R6 refers to generating resources with individual nameplate capacities. For a combined cycle plant, does the individual nameplate capacity of the resource refer to the combined unit or the individual turbines? Recommend making this more clear. 3) Is the list in R6 intended to be an all-inclusive list or is it a minimum list? If it is a minimum list, there is a concern that the standard may allow one entity to put increased costs on another entity, for example a Reliability Coordinator that wants a DDR on every generator, regardless of size. We ask the DMSDT work to address this issue. We recommend that the DMSDT determine the list of places that need a DDR and redraft the requirement to eliminate the responsible entities of the RC and PC and instead just require the owner of elements that meet the specifications install DDRs.
Response: (1) The DMSDT has revised the requirement to remove the use of "locations". **(2) Wording has been added to the Guidelines for R6 (now R5) to clarify generating resource issues.** **(3) The DMSDT notes that this is an all inclusive list and that Part 6.1.3 (now Part 5.1.1) specifies which generators are included. An RC or PC may not ask for DDR data on any other generation. In terms of checks and balances for the Responsible Entity, the intent of the standard is not to implement unnecessary or excessive DDR for collecting wide-area data; rather, the intent is to capture sufficient data "to facilitate event analysis of Bulk Electric System (BES) disturbances." Therefore, the Responsible Entity should not require excessive DDR data requirements on its respective TOs and GOs. To accommodate this concern, a list of "major**		

Organization	Yes or No	Question 4 Comment
transmission interface" criteria has been developed and put in Part 5.1.2 for selecting these "major" interfaces, attempting to minimize ambiguity and excessive requirements.		
Dominion	Yes	However, clarity is needed under 6.1.3 to understand how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples will be most helpful. Also clarity is needed in requirement 6.1.4 when you refer to "monitor all Elements of: all permanent flowgates". If a flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every transformer need to be monitored (lowside or highside side)? Please show some typical examples. Also, under requirement 6.1, it may be better to move the minimum quantities requirements 6.1.1 (minimum 1 DDR per 3000m MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the requirements for 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc...), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable requirements, and state that additional DDR locations are only needed if fulfilling the first 5 does not meet the two extra minimum quantities requirements.
Response: The Guidelines for R6 (now R5) clarify the generating resources specified. **Based on numerous comments, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts are being updated according to industry input as follows. Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer term disturbances on these key interfaces; however, only one Element is required. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by**		

Organization	Yes or No	Question 4 Comment
the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission system coverage of disturbance monitoring). Transformers must be monitored only if they are identified as Elements by the Responsible Entity per the sub-Parts in Requirement R6 (Requirement R6 now R5). The DMSDT has revised R6 (now R5) for clarity.		
Arizona Public Service Company	Yes	
Bureau of Reclamation	Yes	
Corporate Compliance/Engineering	Yes	
Duke Energy	Yes	
Modeling Working Group	Yes	
Pepco Holdings Inc & Affiliates	Yes	
PPL NERC Registered Affiliates	Yes	
AESI Acumen Engineered Solutions International Inc.	Yes	
City of Tallahassee	Yes	
City of Tallahassee (TAL)	Yes	

Organization	Yes or No	Question 4 Comment
Edison Mission Marketing & Trading Inc.	Yes	
Idaho Power Company	Yes	
Manitoba Hydro	Yes	
Public Service Enterprise Group	Yes	
Wisconsin Electric Power Company	Yes	

5. **Do you agree with the VRFs/VSLs and the Drafting Team's justification? If not, please explain why.**

Summary Consideration: Of the comments received for this question, the most common concern was for the use of percentages in determining the severity levels for VSLs. The DMSDT used this approach because of the various BES Elements that recording data will be required for, and it would provide a fair foundation for VSL judgment. The DMSDT also felt that the time frames used in the VSLs were reasonable, and met the desired goal of having recording data expeditiously available. All VSLs and VRFs meet the NERC and FERC Guidelines.

Organization	Yes or No	Question 5 Comment
ACES Standards Collaborators	No	We do not support the standard as written, as it should be consolidated into fewer requirements and should take a more streamlined approach. Since we do not support the standard, we cannot support the corresponding VRFs and VSLs.
Response: The DMSDT combined R1 and R2 (into what is now R1), and R6 and R7 into what is now R5 but did not see any other combinations that would help clarify the standard.		
Arizona Public Service Company	No	R2 and R7 have 10 day time limits before elevating to the next Violation Security Level. This is too short and should be increased to 30 days.
Response: The DMSDT believes the 10 day step before elevating to the next VSL is adequate. In R2 (R1 and R2 have been combined into R1) the Transmission Owner has 90 calendar days to notify Element owners, and in R7 (R6 and R7 have been combined into R5) the Responsible Entity has 90 calendar days to notify the necessary Transmission Owners and Generator Owners. The 10 day steps on top of the initial 90 days are not unreasonable and reflect the importance of those requirements in the standard.		

Organization	Yes or No	Question 5 Comment
Bonneville Power Administration	No	BPA feels that R6 should remove “x percent” of the identified Elements (or Busses) and keep the time-based VSL.
Response: Because of the various Elements identified to have DDR data, it was decided that a fair evaluation of compliance would include the percentage of Elements identified, or a time frame to have that responsibility completed by.		
Corporate Compliance/Engineering	No	Referring to comments for Question 2 on this Comment Form, it would be prudent to at first require a subset of the Fault Recording, SOER and DDR to be up and running and monitored for a time. Then NERC, WECC and entities can refine the standard based upon what we learn. In a nutshell, we should start small.
Response: The DMSDT understands that the industry has experience with installing DME and collecting disturbance monitoring data and there is no need for the implementation of the standard as suggested.		
Florida Municipal Power Agency	No	Please see response to question 7.
Response: Please see the DMSDT response to Question 7.		
Nebraska Public Power District (NPPD)	No	“directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation...” I recommend these be moved to Moderate levels if not lower to match the criteria.
Response: The quote above comes from NERC’s Violation Risk Factors document High Risk Requirement Section. VRF Lower was selected because its definition meets what is required by Disturbance Monitoring. The DMSDT agrees the VRF should be lower. The VSLs are written to address how severely an entity violated a requirement. It is appropriate to have multiple levels because this only addresses the extent to which the violation of the requirement occurred, not the impact to the Bulk Electric System.		

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	The VSLs don't take into account the size of responsible entity. Larger entities should be given more time.
Response: The sizes of the responsible entities were considered during the drafting of the standard, and the times presented were considered to be fair for all size entities.		
Tacoma Power	No	Considering the VSLs for Requirement R4, using "the product of the total number of monitored BES Elements and the number of specified electrical quanitities per each Element" would work well for current on the Element, but what about bus voltage shared by DDR on multiple Elements? Considering the VSLs for Requirements R4, R5, R8, R9, and R11, would it be more appropriate to base the percentages on how many required BES bus locations or BES Elements have the minimum recording properties, electrical quantities, or other specifications/parameters? (Consider the language in the VSLs for Requirement R10.) It seems like determining a percentage of the total recording properties, electrical quantities, or other specifications/parameters may be difficult in some cases. An example (scenario) of how these VSLs, as written, would be applied may be helpful.Should the Severe VSL for Requirement R11 be written something like the following? "The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets less than or equal to 10% of the total recording properties as specified in Requirement R11." In other words, is '1%' intentional?Considering the VSLs for Requirement R13, are the percentages based upon (1) BES bus locations, or BES Elements; (2) recording properties, or electrical quantities; (3) length of data recorded; or (4) a combination? An example (scenario) of how these VSLs, as written, would be

Organization	Yes or No	Question 5 Comment
		applied may be helpful.In the VRF/VSL Justification, the FERC VSL G3 comment for Requirement R11 is missing (page 34).
Response: (1) Requirement R4 (now Requirement R3) does not apply to DDR. (2) This methodology, from a compliance standpoint, makes it easier for the entity to receive credit for incomplete monitoring of bus locations or Elements. (3) The percentages in R13 (Requirement number now R11) refer to the total amounts of data that should have been available. (4) The DMSDT has made a revision to the VSL for Requirement R11 (now R9). The FERC VSL G3 comment for R11 (now R9) was added.		
Tennessee Valley Authority	No	We believe that the time frames in the violation severity levels are too stringent when compared to the other items in the same violation level. A relatively short term delay in communication (30 to 60 days) is much less severe than not performing a function. Suggest lengthening out time frames.
Response: Communication is the foundation for defining what data has to be retrieved to do an analysis, and cannot be discounted. The DMSDT believes the time frames are fair.		
Exelon Companies	No	We don't agree that R3 is necessary at all, see item 7 comments. In a large company hundreds of pieces of equipment require monitoring. If one item out of hundreds are missing, the effect on monitoring is minimal. The DMSDT should consider changing the lower violation severity level to more than X% but less than 95% (instead of 100%). Zero tolerance approaches, especially on standards that "look back" and support analysis are unnecessary and wasteful of engineering resources.

Organization	Yes or No	Question 5 Comment
Response: Regarding Requirement R3 (Requirement R3 now R2) comment, see response in Question 7. **The VSL are written in accordance with FERC guidelines and only come into play when the standard has been violated.**		
Northern California Power Agency	No	No because I do not support the registraton process
Response: Thank you for your comment.		
ReliabilityFirst	No	VSL for Requirement R3 (the same rationale in this comment also apply to the VSLs for Requirement R4,R5, R8, R9, R10 and R11) - ReliabilityFirst believes the gradation of VSLs should be in 10% increments (or similar to the VSL designations for Requirement R1). For example, if an entity only implemented 59% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers, this does not meet the intent of the requirement and therefore should be a “Severe” VSL.
Response: The DMSDT believes the percentages selected are appropriate for the referenced requirements.		
ISO New England Inc.	No	The VSL for R6 calls for the Reliability Coordinator or Planning Coordinator to have “accurately identified the Elements for DDR as directed by Requirement R6”. The term “accurately” should be deleted.
Response: The DMSDT has removed “accurately” from the R6 VSL.		
IRC Standards Reveiw Committee	No	

Organization	Yes or No	Question 5 Comment
Liberty Electric Power LLC	No	
SPP Standards Review Group	Yes	We note in several of the Severe VSLs that quantifiers of greater than 0% but less than 10% are used. However, in Requirement R11, the quantifiers are greater than 1% but less than 10%. Was the 1% intended or should it have also been 0%?
Response: The DMSDT has made a revision to the VSL for Requirement R11 (now R9).		
Bureau of Reclamation	Yes	
Duke Energy	Yes	
Hydro One Networks Inc.	Yes	
New York Power Authority	Yes	
Pepco Holdings Inc & Affiliates	Yes	
PPL NERC Registered Affiliates	Yes	
Reason International, Inc.	Yes	
SERC Protection and Controls Subcommittee	Yes	
Southern Company	Yes	

Organization	Yes or No	Question 5 Comment
Western Area Power Administration	Yes	
AESI Acumen Engineered Solutions International Inc.	Yes	
Ameren	Yes	
American Electric Power	Yes	
City of Tallahassee	Yes	
City of Tallahassee (TAL)	Yes	
Edison Mission Marketing & Trading Inc.	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Ingleside Cogeneration LP	Yes	
ITC	Yes	

Organization	Yes or No	Question 5 Comment
Kansas City Power & Light	Yes	
LCRA Transmission Services Corporation	Yes	
Lower Colorado River Authority	Yes	
Manitoba Hydro	Yes	
N/A	Yes	
Oncor Electric Delivery	Yes	

6. Do you agree with the Implementation Plan? If not, please explain why.

Summary Consideration: The concerns of most of the comments received were directed at the length of time required for implementation of Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10), and R13 (now R11). The schedule for implementation is now to be at least 50% compliant within four (4) years of the effective date of the standard, and 100% compliant within six (6) years of the Effective Date of the standard. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be 100% compliant within six (6) years of the Effective Date of the standard.

Organization	Yes or No	Question 6 Comment
ACES Standards Collaborators	No	The implementation plan is confusing. We do not see the need for a phased in plan, where some requirements are enforceable before others. Assuming standard continues to be developed which we do not support, we recommend consolidating the entire standard to two or three requirements and propose a straight forward implementation plan.
Response: The Implementation Plan was developed based on the technical content of the requirements. The Background Section of the Implementation Plan contains further details. Requirements R1 (R1 and R2 have been combined into what is now R1) and R7 (R6 and R7 have been combined into R5) set the basis for data that is required under other requirements. These must be implemented prior to the data requirements.		
Corporate Compliance/Engineering	No	Referring to comments to Question 2, it would be prudent to at first require a subset of the Fault Recording, SOER and DDR to be up and running and monitored for 2-3 years. Then NERC, WECC and entities can refine the standard based upon what we learn. In a nutshell, we should start small.
Response: In consultation with the NERC event analysis team, the standard requirements are developed to establish the minimum continent wide requirements for DME. It is not necessary to "test out" a subset.		

Organization	Yes or No	Question 6 Comment
Dominion	No	Recommend updating the “entity” for the following requirements on the Implementation Plan Summary:R8 - TOR9 - GOR10 - TO/GO
Response: The Implementation Plan has been corrected. In the latest draft of the standard Requirement R8 is R6, R9 is R7, and R10 is R8.		
Florida Municipal Power Agency	No	Please see response to question 7.
Response: Please see the DMSDT response to Question 7.		
MRO NSRF	No	According to the Implementation Plan, the STD makes it clear that this Standard reflects the need for data, not the equipment used to collect the data. In addition, the DMSDT has already identified that there is already a significant amount of SOER, FR, and DDR equipment currently employed on the BES. The NSRF wants to point out that Section 215 of the Federal Power Act states that the ERO cannot order the construction of additional generation or transmission assets. The NSRF views the purchasing of equipment to provide "data" as construction. The Implementation Plan states that Generator Owners and Transmission Owners may be required to schedule outages to install or implement SOER, FR, and DDR equipment. Installing or implementing of SOER, FR, and DDR equipment is construction because it changes the current equipment configuration to a different configuration. To build on this point, Requirement 12 has the requirement to synchronize the time element. We believe this can only happen with some sort of satellite clock/ gps device, requiring the purchase of said additional device.

Organization	Yes or No	Question 6 Comment
Response: The DMSDT does not interpret the installation of DME equipment as the construction of generation and transmission assets and therefore meets the intent of Section 215. The standard requires the provision of data.		
Nebraska Public Power District (NPPD)	No	It is recommended to have 5 years to become compliant instead of 4 years to match this with the reassessment activities. Since there is no method to track the various percent compliant for the 2nd and 3rd years it is recommended to require 100% compliance by the final year.
Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to: • **At least 50% compliant within four (4) years of the Effective Date of PRC-002-2100% compliant within six (6) years of the Effective Date.** **Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.**		
North American Generator Forum - Standards Review Team (NAGF-SRT)	No	Disagree. Smaller generators who may be drawn into the standard are likely to have only one location to install equipment. This would require 100% compliance within 2 years of notification. If notification occurs soon after a major outage, the generator may be forced to take an unneeded outage just to comply with the standard. Suggest adding the following: For entities with fewer than four locations identified by the TO, entity shall be 100% compliant within four years with no compliance required prior to that date.

Organization	Yes or No	Question 6 Comment
Response: There is a note in the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) that states: **Note: Entities that own only one (1) identified BES bus , BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.**		
Northeast Power Coordinating Council	No	Recommend updating the "entity" for the following requirements on the Implementation Plan Summary: R8 - TOR9 - GOR10 - TO/GOThe Implementation Plan doesn't take into account the size of responsible entity. Larger entities should be given more time (see response to Question 5).
Response: After receiving input from industry, the time frames are reasonable for all size entities.		
Pepco Holdings Inc & Affiliates	No	1) Implementation for Requirement R14, as presently written, applies 9 months after the standard is approved. This requirement needs to be clarified. It should only apply to those SOE, FR, and DDR devices that have been installed in accordance with, and meet the requirements of, this standard. Legacy DME equipment that may exist at one of the busses identified in R1, which does not meet the requirements of this standard, should not be subject to Requirement R14, until the equipment is upgraded, or replaced, to meet the full requirements of this standard. This clarification needs to be made, or, the implementation for R14 should be moved to coincide with the timetable for Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13.

Organization	Yes or No	Question 6 Comment
		2) The timetable for implementation of Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13 allows an entity that owns only one bus location four years to achieve compliance. However, Entities must be compliant with a reassessed list from Requirement R1, Part 1.2 or R6, Part 6.2 within three years following notification of the list. Why this discrepancy? Four years seems appropriate in both cases, in order to schedule the numerous outages necessary to install the equipment, particularly if generation units are connected to the bus.
Response: Requirement R14 (now R12) is intended to only apply to data recording that meets the requirements of PRC-002-2. The DMSDT does not intend for legacy equipment that might not meet the intent of the requirement to be applicable under R14 (now R12). The standard is not concerned with "how" the data is recorded, but "what" data is recorded. We have changed the Implementation Plan to reflect this by having R14 (now R12) become effective three years after approval of the standard. This coincides with the newly revised Implementation Plan whereby entities have to be 50% compliant with the data requirements within four years. R14 (now R12) has been revised to indicate that it applies to data recording applicable under what is now R1, and what is now R5. **The DMSDT believes that a reassessment involves an incremental change and will involve fewer requirements for data. Therefore, a three year implementation is appropriate.**		
PPL NERC Registered Affiliates	No	Since there has been previous DME installation guidance provided by Regional efforts (via a Regional Standards or Criteria), it should be assumed that TOs have previously installed DME (SOER, FR, DDRs) equipment in locations specified per the Regional or local requirements. Therefore, requiring TOs to have any new DMEs installed per R1, R6 within 6-9 months of when PRC-002-2 becomes enforceable is not justifiable. There should be a

Organization	Yes or No	Question 6 Comment
		(12-24 month) grace period to install any newly required DMEs (SOERs, FRS, DDRs) per PRC-002-2 R1 and R6. Concur with implementation time frames of R2, R7 and R14 requirements.
Response: Requirements R1 (R1 and R2 have been combined into what is now R1) and R7 (R6 and R7 have been combined into R5) require determining the list and then providing notification to others. It does not require data recording capability to be implemented during this time frame.		
SERC Protection and Controls Subcommittee	No	1. Extend the GO 100% requirement to 6 years because it better matches the typical major unit overhaul schedule for the large units and plants that this standard targets. 2. Clearly state that the TO / GO has 3 years to attain 100% for any newly identified locations in the five year review.
Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to: **At least 50% compliant within four (4) years of the Effective Date of PRC-002-2** **100% compliant within six (6) years of the Effective Date** **Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.** **The DMSDT has included a note in the Implementation plan which states: "Entities shall be 100% compliant with a reassessed list from Requirement R1 (R1 and R2 have been combined into what is now R1), or R5 (was R6 and R7) within three (3) years following notification of the list."**		

Organization	Yes or No	Question 6 Comment
Southern Company	No	Referencing Note 9 of the Background section, 'Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant'; we feel the requirement to be '25% compliant within two (2) years following notification of the list' is problematic and overly burdensome for both TOs and GOs. We feel that a more appropriate time frame for implementation would be as follows: o At least 25% compliant within three (3) years following notification of the list o At least 50% compliant within four (4) years following notification of the list o 100% compliant within five (5) years following notification of the list
Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to: At least 50% compliant within four (4) years of the Effective Date of PRC-002-2 100% compliant within six (6) years of the Effective Date. Note: Entities that own only one (1) identified BES bus , BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.		
Tacoma Power	No	The disagreement is not so much with the implementation plan itself but whether part of the implementation plan should reside within the standard itself. More specifically, should part of the implementation plan be included under Requirements R3, R4, R5, R8, R9, R10, R11, R12, and R13? Of primary concern are BES bus locations or BES Elements that are added as part of the review at least once every five calendar years. An implementation plan normally

Organization	Yes or No	Question 6 Comment
		addresses phasing in of the standard, or new version of the standard, not ongoing implementation.
Response: The Implementation Plan is approved in the same manner as the standard. It is balloted along with the standard, approved by the BOT and filed with regulatory authorities simultaneously with the standard. The Implementation Plan and its provisions will remain separate from the standard. **The following has been added to the end of the Implementation Sections:** **Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.**		
Ameren	No	We request the DMSDT to make the following changes: (1) Add 1 month to item 3 for the TO to identify BES Elements in R1. (2) Delete 'bus locations and' in item 6 so that the total percentage (%) is based on BES Elements throughout the Implementation Plan. There are bus locations at which there are several different owners of the BES Elements. (3) Replace '24 months or more' with 'up to 60 months' in item 9. (4) The Implementation Plan Summary is very helpful but the Entity is incorrect for R8, R9, and R10.
Response: **1) The DMSDT believes that there is sufficient time to implement the standard.**		

Organization	Yes or No	Question 6 Comment
2) Item 6 is just an informational statement. Requirement R1 (Requirements R1 and R2 have been combined into what is now R1) addresses BES buses while Requirement R6 (now R5) addresses BES Elements. The statement in item 6 provides appropriate information regarding these two requirements. 3) Item 9 is an informational statement only. There are instances where outage cycles are as short as 24 months, but they can also be much longer. 4) The table has been revised to reflect the latest updates to the standard and Implementation Plan.		
American Electric Power	No	We believe the implementation plan will be sufficient, however we cannot state that with absolute certainty until the completion of the identification processes in R1 and R6. At this time, the actual scope is still unknown.
Response: Thank you for your comment.		
CenterPoint Energy Houston Electric	No	CenterPoint Energy is concerned the proposed Implementation Plan does not allow sufficient time for entities to make arrangements with other entities or, if needed, to install required devices or communication devices. Based on Requirement R6 the ERCOT Region would require approximately 18 - 20 DDR's and several times that amount of SOER's. The installation of DDR's and SOER's would require scheduling outages on possibly hundreds of pieces of equipment. The scheduling and coordination of this amount of planned outages is simply not possible within the allotted time frame. CenterPoint Energy recommends expanding the Implementation Plan to three to five years.
Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to:		

Organization	Yes or No	Question 6 Comment
At least 50% compliant within four (4) years of the Effective Date of PRC-002-2 100% compliant within six (6) years of the Effective Date. Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.		
Dairyland Power Cooperative (DPC)	No	It is unclear what the implementation time frame is for newly identified facilities after the original implementation of the standard. Should a facility be identified in the future as requiring a SOER, FR or DDR it is unclear how long the responsibility entity has to install equipment to capture the necessary data to be compliant.
Response: **There is a section of the Implementation Plan which states: "Entities shall be 100% compliant with a reassessed list from Requirement R1 (now R1), or R5 (wasR6) within three (3) years following notification of the list."**		
Dynegy	No	The two/three/four year requirement for a GO to be 25%/50%/100% compliant should be increased to three/four/five years to give more time to budget these large capital expenditures.
Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to: At least 50% compliant within four (4) years of the Effective Date of PRC-002-2 100% compliant within six (6) years of the Effective Date.		

Organization	Yes or No	Question 6 Comment
Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.		
Entergy Services, Inc.	No	Clearly state the time frame required for implementation of newly identified locations resulting from the R1 five year assessment.
Response: There is a line at the end of the Implementation Plan Sections of the Implementation Plan which states: **"Entities shall be 100% compliant with a reassessed list from Requirement R1 (now R1), or R5 (was R6) within three (3) years following notification of the list."**		
Idaho Power Company	No	Protection Engineering: The 4 year implementation plan could be challenging to fit into our project process. We employ a 3 year cycle with definition in year 1, scope/design in year 2, and construction in year 3. Any delays in any given year could cause us to exceed the requirement.
Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to: **At least 50% compliant within four (4) years of the Effective Date of PRC-002-2** **100% compliant within six (6) years of the Effective Date.** **Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.**		
ISO New England Inc.	No	Installation of potentially 200 additional DDRs will take far longer than the time specified in the Implementation Plan.

Organization	Yes or No	Question 6 Comment
Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to: **At least 50% compliant within four (4) years of the Effective Date of PRC-002-2** **100% compliant within six (6) years of the Effective Date.** **Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.**		
Kansas City Power & Light	No	We do not agree based on our earlier comments in regards to Attachment 1.
Response: Please see the DMSDT response to those comments in Question 2.		
Liberty Electric Power LLC	No	See the NAGF SRT comments. Smaller entities who may have one SOE system to install will be forced to comply 100% within two years.
Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to: **At least 50% compliant within four (4) years of the Effective Date of PRC-002-2** **100% compliant within six (6) years of the Effective Date.** **Note: Entities that own only one (1) identified BES bus , BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.**		
Manitoba Hydro	No	The times for meeting requirements R1 and R6 are adequate. However, the time of 9 months required for complying with requirements R2, R7 and R14 is too short, especially considering that R14 may require troubleshooting, testing,

Organization	Yes or No	Question 6 Comment
		shipping, repairs, possible replacement of the failed FR, SOER or DDR, possible discussions with suppliers, design and drawing considerations if the replacement is not identical, etc. Given the existing demands on maintenance and design staff, and the need to also develop a corrective action plan for the Regional Entity, the DMSDT should consider extending this time.
Response: Requirements R2 (now R1) and R7 (R6 and R7 have been combined into R5) only require notification of identified buses or Elements. Requirement R14 (now R12) requires an entity to restore the recording capability OR develop a corrective action plan (CAP) within 90 days. The CAP should identify a timeline within which the repairs will be completed. Repairs do not necessarily have to be within 90 days but must take into account design and maintenance considerations. The intent of the requirement is to restore recording capability as soon as practical while taking into consideration workload and other factors which may hinder timely repairs.		
Northern California Power Agency	No	I do not agree with the registration
Response: Thank you for your comment.		
Portland General Electric Company	No	Portland General Electric Company (PGE) appreciates the standard DMSDT's efforts in crafting this proposed standard and understands the importance of the data that will eventually be available once the standard is implemented. However, a four (4) year implementation window may not be enough time if an entity is required by its Responsible Entity (in our case, the RC) to install several disturbance monitoring units.

Organization	Yes or No	Question 6 Comment
		It is interesting to note that an entity that has only one element to implement has the entire 4 year window to do so. However, if an entity has 2 elements, for example, that entity does not get 8 years to implement but, in effect, has half the time. The more elements required to be implemented, the less overall time an entity has to do so. PGE suggests letting the RC develop an implementation time frame based on the elements it determines an entity needs to install. Depending on the number of elements required, an entity would be considered compliant as long as it was meeting specified and agreed upon milestones. The triggering of the negotiated time frames could be based on a pre-determined number of elements, i.e. >4, or on a business-justified request from the entity for an extended implementation window. To suggest that an entity is non-compliant because all necessary projects are not fully completed after a 4 year implementation window fails to distinguish between entities that have taken no action whatsoever and entities that have projects and activities in progress well ahead of the effective date of this proposed standard.

Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to:

At least 50% compliant within four (4) years of the Effective Date of PRC-002-2
100% compliant within six (6) years of the Effective Date

Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.

Organization	Yes or No	Question 6 Comment
Wisconsin Electric Power Company	No	Item 5 This item references a nine month time frame associated with R14. There does not appear to be any such time frame listed under R14. Since the required in-service dates for DME are from two to four years, that time frame should determine the compliance date for R14.
Response: Requirement R14 (now R12) is intended to only apply to data recording that meets the requirements of PRC-002-2. We have changed the Implementation Plan to reflect this by having R14 (now R12) become effective nine (9) months after approval of the standard. This coincides with the newly revised Implementation Plan whereby entities have to be 50% compliant with the data requirements within four years.		
Xcel Energy	No	1) Our concern with the implementation plan is that its milestone requirements are significantly different from requirements for similar equipment in PRC standards that are now awaiting final FERC approval. Specifically, PRC-019, PRC-024, & PRC-025 involve the same facilities and all have 5 year implementation plans (with some caveats). Yet the implementation plan for PRC-002 is 4 years. When entities are considering work planning and execution, it would be more efficient to provide an implementation schedule that allows 'campaigns' at generation facilities to address all of the protective system equipment changes due to the suite of PRC standards under one maintenance project. (This is especially critical when considering this work will likely require an outage.) Therefore, Xcel Energy recommends PRC-002 utilize the same phased in schedule as PRC-019, PRC 024 and PRC-025. At a high level, the modification would be to change the implementation plan to:[Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13:-Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that additional

Organization	Yes or No	Question 6 Comment
		equipment is not necessary, the first day 60 months from notice of applicability of R1 or R6.-Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that additional equipment is necessary, the first day 84 months.] 2) Finally, the standard is written such that the requirements are phased in over time. However, there is no period identified for the TO or GO to become compliant after any change in the points identified. As an example, in 2020, if the TO determines in R1 that a new point needs a device, R2 allows them 90 days to notify the owner of that equipment. Yet, for R3, R6 and R7 there is no established period of time for the TO or GO to make such an installation. We recommend the DMSDT add in an implementation period for newly identified points beyond the immediate phased-in implementation of the standard.
Response: 1) **The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to:** **At least 50% compliant within four (4) years of the Effective Date of PRC-002-2** **100% compliant within six (6) years of the Effective Date.** **Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.** **2) The Implementation Plan provides three years for TO or GO to be 100% compliant with a reassessed list.**		
Colorado Springs Utilities	No	

Organization	Yes or No	Question 6 Comment
Western Area Power Administration	Yes	Overall, the implementation program appears reasonable. However, the work involved is linked to the requirements of the standard which could possibly change. The requirements of R6 may be difficult to meet as written. See comments under Question 4.
Response: See the DMSDT response to Question 4.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration L.P. believes that the two to four year deployment schedule for recording capability is sufficient.
Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11)to: **At least 50% compliant within four (4) years of the Effective Date of PRC-002-2** **100% compliant within six (6) years of the Effective Date.** **Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.**		
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Bureau of Reclamation	Yes	

Organization	Yes or No	Question 6 Comment
Duke Energy	Yes	
El Paso Electric	Yes	
Hydro One Networks Inc.	Yes	
IRC Standards Reveiw Committee	Yes	
New York Power Authority	Yes	
Reason International, Inc.	Yes	
Tennessee Valley Authority	Yes	
AESI Acumen Engineered Solutions International Inc.	Yes	
American Transmission Company, LLC	Yes	
City of Tallahassee	Yes	
City of Tallahassee (TAL)	Yes	
Edison Mission Marketing & Trading Inc.	Yes	

Organization	Yes or No	Question 6 Comment
Exelon Companies	Yes	
Independent Electricity System Operator	Yes	
ITC	Yes	
LCRA Transmission Services Corporation	Yes	
Lower Colorado River Authority	Yes	
Luminant Generation Company LLC	Yes	
N/A	Yes	
Oncor Electric Delivery	Yes	
PJM Interconnection	Yes	

7. If you have any other comments that you haven't already mentioned above, please provide them here:

Summary Consideration: Based on stakeholder comments, the DMSDT made significant revisions to PRC-002-2 including:

- **Combined Requirements R1 and R2.**
- **Combined Requirements R6 and R7.**
- **Removed references to "equipment" and specified data requirements for FR, SER and DDR.**
- **Removed references to "locations" and replaced "bus" with "BES bus"**
- **Updated rationales with clarifications and more general information for each requirement.**
- **Revised Requirement R6 (now R5) for more clarity regarding DDR data requirements.**
- **Revised the VSLs to conform to the revised requirement language.**
- **Added language to the Guidelines and Technical Basis section of the standard.**

Organization	Question 7 Comment
Texas Reliability Entity	(1) For Requirements R2-R5 at substations where there are multiple Transmission Owners, are entities allowed to use a shared FR/SOER, or is each entity individually responsible for the Elements that they own? (2) For Requirement R14, there appears to be an "or" missing following the 1st bullet, "Restore the recording ability, or". The DMSDT may want to consider having the entity reporting DDR failures report to the Responsible Entity as well as the Regional Entity, so that the Responsible Entity can look at possible alternative methods to monitor the Elements required per R7.
Response: (1) The Transmission Owners are allowed to use shared FR/SOER (now SER). The Transmission Owner of the Element for which data is to be captured is responsible for the capture of that data. The standard addresses "what" data must be captured, not "how" it is captured. (2) A list with bulleted items is an "Or" list for the bulleted items.	

Organization	Question 7 Comment
Tennessee Valley Authority	(1) We feel that the first bullet of 5.1 is not needed due to the content of the second bullet. If the team determines that it does need to be kept, a post-trigger record length of 30 cycles for the same trigger point would be adequate. (2) For R14, please provide additional clarity around the fact that if the equipment is returned to service within the 90 day time limit then it does not have to be reported. Respectfully suggest the second bullet to change to, “If not returned to service within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability.”
Response: (1) A list with bulleted items is an “Or” list for the bulleted items. “Or” will be added between the bullets of Part 5.1 (now Part 4.1) for clarification. Both bullets of 4.1 are needed to address the Fault Recording that is available to industry. The DMSDT has made the revision to 30 cycles. **(2) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can’t be achieved then a CAP would have to be submitted to the Regional Entity. R14 (now R12) was revised for clarification.**	
Manitoba Hydro	(1) An acronym is given for each of Sequence of Events Recording (SOER) and Fault Recording (FR) and Dynamic Disturbance Recording (DDR) but the acronyms are never used, and sometimes the full phrase is used without the acronym noted. This occurs throughout the standard and should be made consistent and cleaned up. If the acronyms are not going to be used, there is no need to state them. (2) R1, 1.2 - would be clearer to state 'identified bus locations should be reassessed at least once every five calendar years’. (3) M1 (same applies for all measures) - should be written to say that the entity 'shall have' not 'has'.

Organization	Question 7 Comment
	(4) M1 - the last few words of the measure that deal with 1.2 are not complete - 'assessed within the required interval' should be 'and evidence that the identified bus locations have been reassessed within the required interval'. (5) R2 - would be more consistent with the rest of the standard to refer to 'BES bus locations' rather than 'locations' and 'identified' instead of 'established' and 'identification' instead of 'determination'. (6) M2 - would be more consistent to say 'BES Elements' rather than just 'Elements' and 'at the BES bus locations identified' as opposed to 'established' and 'notice' instead of 'information'. The measure is also missing the time frame. (7) R3/M3/R4 - the reference to Requirement R2 does not seem correct in this context - should be those BES bus locations identified in R1? (8) M3 - the description of the circuit breaker position in M3 is lacking specificity that appears in requirement - '(open/close) for each.....' (9) R4 - for consistency, 'bus locations' should be 'BES bus location' and 'as per' should be 'identified in'. (10) R6, 6.2 - would be clearer to state 'the identified BES Elements shall be reassessed at least once every five calendar years'. (11) M6 - would be more complete to state 'The Responsible Entity shall have a dated (electronic or hard copy) list of BES Elements for which Dynamic Disturbance Recording (DDR) is required as identified in accordance with Requirement R6 and evidence that such identified BES Elements have been reassessed within the required interval.' (12) R7 - reference to 'the locations' needs to be more specific - is this the 'BES bus locations'? To be consistent, 'Elements' should be 'BES Elements' and 'established in' should be 'identified in'. (13) M7 - would be clearer if reference to 'owners' was to 'each Transmission Owner and Generator Owner'. 'established' should be 'identified' to be consistent. (14) R8 - 'Element' should be 'BES Element'. The words 'for which they received notification' could be added after 'own'.

Organization	Question 7 Comment
	(15) R9 - same comments as R8 (16) R10 - the reference to R7 does not seem correct - is this meant to be R8 or R9 as it is these parts that put obligation on the TO and GO, whereas R7 puts an obligation on a responsible entity? Reference to 'equipment' seems vague - is this DDR equipment? (17) M10 - reference to 'data recording' should be to DDR? (18) R11 - as above, the reference to R7 does not seem correct - should be R8 or R9? 'Element' should be 'BES Element'. (19) R12 - as above, reference to R7 should be to R8 or 9? 'Element' should be 'BES Element', 'bus locations' should be 'BES bus locations' and the word 'identified pursuant to' should replace 'as per' to be consistent. (20) R13 - same comments as R12. (21) M13 - the words 'data was submitted' should be replaced with 'that SOER, FR and DDR data was provided to the Reliability Coordinator, Regional Entity or NERC upon request'. (22) R14 - same comments as R12.

Response: (1) The use of acronyms in the standard (including the Rationale Boxes) was reviewed by the DMSDT.FR is for fault recording, SER is for sequence of events recording, and DDR is for dynamic disturbance recording.

(2) Requirements R1 and R2 were combined into what is now R1. Part 1.2 was revised to read that bus identification would be performed upon changes to its portion of the BES OR at least once every five calendar years.

(3) The use of the word "has" is stipulated in NERC Measure writing guidance.

(4) The wording of M1 was revised for clarification. Measures M1 and M2 were combined (into what is now M1).

(5) Requirements R1 and R2 were combined (into what is now R1). Wording was made consistent throughout the standard.

(6) Requirements R1 and R2 and their associated Measures were combined (into what is now R1). Wording was made consistent throughout the standard.

Organization	Question 7 Comment
(7) Requirements R1 and R2 were combined (into what is now R1), and the references revised accordingly. The list is used by the TO and GO to provide the appropriate data recording. (8) Measure M3 (now M2) has been revised to be more specific. (9) The R4 (now R3) wording was reviewed for consistency, and revised accordingly. (10) Part 6.2 (now Part 5.3) was revised and clarified. (11) Measure M6 (now M5) was revised based on revisions that were made to Requirement R6 (now R5). (12) The R7 (R6 and R7 have been combined into R5) wording was revised. (13) M7 (now M5) was revised as suggested. (14) The R8 (now R6) wording was revised. (15) The R9 (now R7) wording was revised. (16) The reference to R7 (R6 and R7 have been combined into R5) in R10 (now R8) includes both the Transmission Owner and the Generator Owner, and it is not necessary to be more specific. Because R10 (now R8) deals with DDR, it is understood that the equipment is only that equipment used to capture the DDR. (17) Measure M10 (now M8) wording is only applicable to Requirement R10 (now R8). (18) In R11 (now R9), the reference to R7 (R6 and R7 have been combined into R5) is appropriate because R7 (R6 and R7 have been combined into R5) specifies the locations and BES Elements to be captured by DDR. Requirements R8 (now R6) and R9 (now R7) address the specifics of the data that is to be recorded. The use of "Element" versus "BES Element" was revised. (19) In R12 (now R10) the reference to R7 (R6 and R7 have been combined into R5) is appropriate because R7 (R6 and R7 have been combined into R5) specifies the notifications of Elements to be captured by DDR. Requirements R8 (now R6) and R9 (now R7) address the specifics of the data that is to be recorded. The use of "Element" versus "BES Element" was revised. "As identified" and "according to" replaced "as per".	

Organization	Question 7 Comment
(20) In R13 (now R11) the reference to R7 (R6 and R7 have been combined into R5) is appropriate because R7 (R6 and R7 have been combined into R5) specifies the locations and Elements to be captured by DDR. Requirements R8 (now R6) and R9 (now R7)address the specifics of the data that is to be recorded. The use of "Element" versus "BES Element" was revised. "As identified" and "according to" replaced "as per". **(21) The wording in M13 (now M11) was revised to match the revised requirement.** **(22) In R14 (now R12) has been revised to reference what is now R5 (R6 and R7 have been combined into R5). Requirements R8 (now R6) and R9 (now R7) address the specifics of the data that is to be recorded. "As identified" and "according to" replaced "as per".**	
Duke Energy	(1) Duke Energy believes that ambiguity exists between Requirement 14 and the Rationale. The standard suggests that an entity must "Report the inability to record data to the Registered Entity along with a Corrective Action Plan (CAP) to restore the recording ability" within 90 calendar days. However, in the Rationale for Requirement 14, the language suggests that a Registered Entity must issue a report on the inability to record data to the Registered Entity after a time frame of 90 days. (2) Triggering of frequency events in Requirement 10 should be adjusted. Significant events will be missed if recorders on generators are set to trigger below 59.75. Also, the rate of change wording is confusing and should trigger if the rate of change is greater than a value not less than a value. Lastly, the Rate of change frequency set point of 125 mHz is too large and should be triggered on generation around 20 mHz per second. (3) Electrical quantities identified in Requirement 9 should better align with MOD-26 (MW, MVARS, Terminal Volts, Field Volts, Field Amps). (4) According to the rationale for R6, the intent of the requirement is to "ensure that there are sufficient BES Elements identified for DDR because of the crucial role DDR plays in wide-area disturbance analysis. Additionally, DDR is used for capturing the Bulk Electric System transient

Organization	Question 7 Comment
	and post-transient response and for validating the system model's performance." Duke Energy believes to require that DDRs be located in areas necessary to monitor all elements of permanent Flowgates is excessive. Permanent Flowgates fall into one of three categories: Voltage, Stability, or Thermal. The majority of the Flowgates identified are classified as being Thermal. Thermal Flowgates are chosen due to concerns with steady-state loading and not for transient/post-transient activity. With some PCs or RCs having as many as 1000 permanent Flowgates, the cost versus reliability gain would be astronomical. For Flowgates that have been identified to be voltage or stability related, the case can certainly be made to have DDRs monitor them in the transient/post-transient time frame. We suggest that all permanent Flowgates should be removed from the requirement and only keep those permanent Flowgates that have been identified as voltage or stability limited. This would reduce the amount of Flowgates requiring DDRs, reduce the cost for industry stakeholders, and still achieve the intent of this requirement.

Response: (1) Requirement R14 (now R12) and its Rationale Box have been revised for clarity.

(2) Triggering values were chosen based on research and analysis of frequency response for each respective Interconnection. The values are intended to capture significant events. Requirement R10 (now R8) also only applies "If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording". Rate of change of frequency triggers were chosen to match the off-nominal frequency triggers and should be "less than" because the thresholds are negative quantities.

(3) The purpose of the standard is for disturbance monitoring, not to verify models. Therefore these quantities are outside the scope of the standard.

(4) Requirement R6 (now R5) has been revised regarding the use of Flowgates. Please refer to the comments /responses for Question 4.

Organization	Question 7 Comment
Seminole Electric Cooperative, Inc.	(1) In Requirement R5.1, are the two bulleted items both required, or is only one item required, i.e., are the bulleted items listed with a coordinating conjunction of “and” or “or”? From past balloting on other Standards, e.g., CIP Standards, a numbered list in the Measure/Requirement mean the evidence example includes all of the items in the list. In contrast, a bulleted list provides multiple options of acceptable evidence.” Seminole requests clarification on this concern. (2) In Requirement R14, Seminole reasons that the requirement is intended to require the filing of a CAP if the inability to record data exists for longer than 90 consecutive calendar days. This reasoning is in line with the Rationale box for Requirement R14, however, the actual Requirement appears to require the filing of a CAP notwithstanding if the failure is remedied within 90 calendar days of discovery of the failure. Seminole requests that the requirement be revised to state that the filing of a CAP is only required if the inability to record exists for more than 90 calendar days from the date of discovery. (3) In Requirement R14, are the two bulleted items both required, or is only one item required, i.e., are the bulleted items listed with a coordinating conjunction of “and” or “or”? From past balloting on other Standards, e.g., CIP Standards, a numbered list in the Measure/Requirement mean the evidence example includes all of the items in the list. In contrast, a bulleted list provides multiple options of acceptable evidence.” Seminole requests clarification on this concern. (4) In Requirement R14, it appears that the intent of the DMSDT was to require the submission of a CAP if the failure was not remedied within 90 calendar days. If the failure is not remedied within 90 calendar days, it appears from the Requirements and the VRF/VSL penalty matrix that a CAP is required to be submitted to the RE within the same 90-day window. Seminole requests that the time to submit a CAP be extended an additional 30 calendar days to read that an entity has 120 calendar days from the date of discovery of a failure in which to submit a CAP to its RE. This would allow a true 90-day window for fixing the CAP. For example, under the current language if

Organization	Question 7 Comment
	an entity believes it will have remedied a piece of equipment on day 83, it would probably be best practice for that entity to prepare a CAP for submission in order to meet the 90-day CAP 29submission window in case delays arose. Seminole believes that this is not in line with the intent of the DMSDT and Seminole request the additional 30-day window for submission of a CAP, i.e., 120 days from date of discovery of the failure, and for Requirement R14 and the penalty matrix to reflect this change.
Response: (1) A list with bulleted items is an "Or" list for the bulleted items. "Or" will be added between the bullets of Part 5.1 (now 4.1) for clarification. **(2) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be filed with the Regional Entity. R14 (now R12) was revised for clarification.** **(3) A list with bulleted items is an "Or" list for the bulleted items. Requirement R14 (now R12) was reworded for clarification.** **(4) The intent of Requirement R14 (now R12) is to have an entity restore recording ability within 90 days, but if that 90 day window couldn't be met then the Regional Entity would have to be notified along with a Corrective Action Plan and timeline for the recording ability restoration. The 90 day window is realistic and practical, and compliance should not be burdensome to an entity. Requirement R14 (now R12) was revised for clarification.**	
ACES Standards Collaborators	(1) This standard is unnecessary because there are already significant amounts of PMU data to construct sequence of events and other post-event analysis of disturbances. As referenced in the Southwest Blackout Report of 2011, there is a multitude of disturbance monitoring devices installed on the electric grid. The Southwest Blackout Report states, "PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP)." We do not see the cost benefit of requiring additional resources for an issue that is not a high priority for reliability.

Organization	Question 7 Comment
	(2) As stated above, there are financial incentive programs through other federal agencies that provide funding for disturbance monitoring equipment. We recommend that NERC work with those programs to develop a technical guideline to ensure these devices are installed and monitoring critical areas of the electric system. (3) Why has the DMSDT decided to include 14 requirements to this project? In light of recent standards projects like Paragraph 81, the industry is supporting reducing and consolidating the amount of requirements. We do not see the need to have 14 requirements for disturbance monitoring. While we do not believe the standard is needed, we strongly recommend that the DMSDT revise this standard to two or three requirements if it persists. The amount of detail is unnecessary and poses a serious compliance burden on registered entities. (4) R2 requires implementation within ninety days of Fault Recording and Sequence of Events Recording devices following a notification provided by the Transmission Owner. We question if this will provide entities sufficient time to acquire such devices from their suppliers. Moreover, entities can be, from time-to-time, directed to suspend maintenance activities on their BES elements due to extreme weather conditions or more immediate system level emergencies. These entities plan their maintenance activities months in advance, only to have such activities delayed by days or weeks as necessary to maintain system reliability. We recommend extending the period required within R2 to at least twelve months, as this should be sufficient time to acquire and install these recording devices during non-peak calendar dates. (5) We feel that R8 and R9 do not adequately accommodate joint substation facilities and shared resources. As stated, the burden to install Dynamic Disturbance Recording devices falls on each individual Transmission Owner and Generator Owner. Sharing such installations limits the number of connected measuring devices to facility structures, including current and potential transformers, further limiting the possibility that one of these measuring devices catastrophically fails and leads to a more significant impact on the facility's availability because they are jointly owned.

Organization	Question 7 Comment
	(6) We previously commented that an appendix, modeled similarly like in Standard PRC-023-2, would be a better alternative to Requirement R6. Likewise, including details like those listed in R12 would further strengthen a case to incorporate this appendix in the Standard and not subject registered entities to possible violations for every requirement. W`e feel that technology has significantly improved since 2003, as manufacturers have supported the need to align such devices on a common frame of time. Still R12 places the burden on registered entity, when it seems more appropriate to be included in a manufacturer technical specification. (7) We feel Requirement R13 is arbitrary, could be subject to interpretation from auditors and meets paragraph 81 criteria. Transmission Owners and Generator Owners could be required to prove the negative, and demonstrate that they have not received a request to provide device data to their Reliability Coordinators, Regional Entities, and NERC. Furthermore, this standard meets several Paragraph 81 criteria including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. The requirement is administrative because it compels data formats that are immaterial to reliability with the sole purpose to simplify data collection and communication. It meets the data collection/data retention criterion because the requirement is about collecting data. It also meets the reporting criterion because it compels data reporting. Please strike the requirement in its entirety. It would be more appropriate to include in a guideline. (8) We believe numerous requirements of this Standards fall under Paragraph 81 Criteria B, and are thus unnecessary. For instance, we feel requirements R1.2 and R6.2 are "Periodic Updates" due to the need to reassess each list every five calendar years. Likewise, we feel requirements R2, R7, and R13 are "Administrative" due to the need to collect, organize, format, and then circulate data and communications sent to identified entities within a specific time frame. We feel that several other requirements could be "Data Collection" in nature. Requirements R5.1, R5.2 require the collection of data according to specifications outlined for the minimum recording rate and data duration. Requirements R10.1 and R10.2 require the collection of data according to specifications outlined for the trigger record lengths and trigger settings. Likewise, Requirements R11.1 and R11.2 require the

Organization	Question 7 Comment
	collection of data according to specifications outlined for input sampling rate and output recording rate. Requirement R12 require the collection of data according to specifications outlined for time synchronization. Finally, Requirement R14 is "Administrative" and "Documentation" in nature based on the need to circulate the discovery of device failure within a specific time frame and provide a Corrective Action Plan to the Regional Entity if repair is outside this time frame. (9) The costs of installing new equipment for disturbance monitoring could be significant for our members. We find this standard is unnecessary and NERC should work with the Department of Energy (DOE) to further expand the use of grant money to supply registered entities with funding for these types of monitoring equipment. The prior grants from the DOE have been very successful and we see no reason to require these monitoring devices to be subject to enforceable reliability standards. There is no convincing evidence that these standards are being developed to address a reliability need. We see no justification for industry to allocate resources to disturbance monitoring equipment when there are other priorities that should be addressed first, such as cyber security. Furthermore, the joint NERC and FERC report on the September 8, 2011 outage in Arizona and southern California further demonstrates that there is not a need for the standard. It stated that there was ample event data that was recorded and used to analyze the event. (10) We appreciate the opportunity to comment on the cost of developing this standard (CEAP process). However, the timeline of submitting comments should align with the ballot and comment deadlines. It is unreasonable to set the comment deadline for the CEAP two weeks before the project comment deadline, considering the due date is Monday following Thanksgiving. We are concerned that industry was not aware of this deadline and did not have adequate time to prepare comments. (11) Thank you for the opportunity to comment.

Response: (1) (2) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:

"Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.

Organization	Question 7 Comment

A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices."

Project 2007-11 – Disturbance Monitoring was initiated to address the existing PRC-002-1 "fill in the blank" standard. FERC did not approve or remand PRC-002-1 in its Order No. 693 (March 16, 2007) because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the "fill in the blank" aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). The consolidation of these two Standards will result in a Standard that fully addresses what is necessary to capture power system disturbance data.

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data.

The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.

(3) As the DMSDT put together the standard, the number and necessity of requirements was reviewed, and the Paragraph 81 project referenced. The requirements in the standard are the minimum number that meets the Purpose of the standard. Consolidating requirements results in multiple reliability objectives in a single requirement.

(4) The ninety day period in Requirement R2 is a reasonable and practical time frame for implementing notification. The Implementation Plan stipulates the schedules for having to have the capabilities in service. Requirements R1 and R2 have been combined (into what is now R1).

(5) Requirements R8 (now R6) and R9 (now R7) apply to BES Elements and not substations facilities and shared resources. The owner of a particular Element is responsible for providing data.

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(6) Requirement R6 (now R5) has been revised, and the DMSDT has retained it in the body of the standard. The specifications enumerated in the Requirements of the standard are to ensure the adequacy of the data captured. **(7) The 2003 Northeast Blackout exposed the need for capturing complete data to analyze a disturbance. Disturbance analysis leads to improved system operations and equipment installations. To facilitate expeditious and reliable data capture, it is necessary to stipulate the data formats necessary for efficient data analysis. The more efficient and effective data capture, the more aggressively system reliability improvements can be applied.** **(8) Disturbance Monitoring recording is necessary to ensure the reliability of the BES by providing the data for a post event analysis that can determine if system improvements are necessary to ensure reliability. Disturbance Monitoring data can also be used to guide real-time operating decisions. The supporting Requirements are necessary, but may be deemed administrative. The approved standard will be subject to a Paragraph 81 review.** **(9) PRC-002-2 does not deal with equipment, but with data. Costs associated with meeting PRC-002-2 are considered in the CEAP posting. Refer to the responses to comments (1) and (2) above.** **(10) The Standards Committee is aware of this concern, and the CEAP was reposted to accommodate this concern. As the CEAP is used in the future the timeliness of its posting will be considered.**	
Pepco Holdings Inc & Affiliates	(1) Requirement R2 should be re-written as follows: Each transmission Owner that identifies BES Elements, which are owned by other entities, at the locations established in Requirement R1 shall notify the owners of those Elements ..... By adding the phrase - which are owned by other entities - eliminates the need to unnecessarily provide documentation that it notified itself of the requirement. (2) Requirement R4 Part 4.1 should be re-written as follows: Phase-to-neutral voltages for each phase of either each BES line or bus. The term BES must be added to provide clarity and to be consistent with Part 4.2 and the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide voltage monitoring on non BES radial lines, or distribution transformers connected to the bus. (3) Requirement R8 should be re-written as follows: Each Transmission Owner shall have Dynamic Disturbance Recording (DDR), for each BES Element they own as per Requirement R7, to determine

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	the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES radial lines, or distribution transformers connected to the bus. (4) Requirement R9 should be re-written as follows: Each Generator Owner shall have Dynamic Disturbance Recording (DDR), for each BES Element they own as per Requirement R7, to determine the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES station service transformers connected to the bus. (5) Requirement R13 Part 13.2 poses an indeterminate requirement on the size of the hard drive required to archive data. The present requirement states that the data will be retrievable for the period of 10 calendar days preceding a request. However, there is no requirement on how long after an event the request might be made. If the request was not made until six months after the event, would the data have to be retrievable for six months after the event? In order to place certainty on this data storage requirement Part 13.2 should be re-written as follows: The recorded data will be retrievable for a period of 10 calendar days following an event. This places a limit on data storage capacity and also makes it clear that a request for data must be made within 10 calendar days of the event. (6) Requirement R14 needs to be re-written to be consistent with the intent of the requirement as expressed in the shaded box describing the Rationale for R14. As presently written, R14 requires that the Owner must both restore recording ability AND report the inability to record data to the Regional Entity. To be consistent with the Rationale, Requirement R14 should be re-written as follows: Each Transmission Owner and Generation Owner, upon discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recording (DDR) at the bus locations as per Requirement R2 and elements as per Requirement R7, shall restore the recording ability within 90 calendar days, OR , if the recording capability cannot be restored within 90 days, report the

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	inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability. (7) In the Guidelines and Technical Basis in the next to last paragraph of the section on Guideline for Requirement R1 it states that there is no requirement for SOER and FR for generating units. Later in the section on Guideline for Requirement R4 it states that generator step-up transformers are excluded from fault recording. If so, why is Generator Owner listed as an applicable entity in Requirement R4? It makes sense to list them in R3, since they may own breakers connected to Transmission Owners bus, but the GSU Transformer, station service transformer, and generator itself would not qualify for Fault Recording. (8) There is no specific requirement for the sampling rate for SOER within the standard itself. In the Guidelines and Technical Basis section on Guideline for Requirement R5 it states that a minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for SOER. There are a vast number of microprocessor relays currently installed on the system that have a sampling rate of 16 samples per cycle for analog inputs, however, the digital inputs, which would be used for SOE recording, are only sampled every quarter cycle. Existing regional DME standards and criteria recognize this and permit these types of microprocessor relays to be acceptable for both FR and SOER applications. As such, in order to allow these devices to continue to be an acceptable application, we would suggest two requirements be added for SOER devices, similar to that included in the RFC DME criteria, that states: SOER recording equipment should be capable of determining and recording the time that an input is received to within one quarter of an electrical cycle (or less) of input change of state. SOER recording equipment should have time stamp capability to record seconds to at least three decimal places (i.e. ss.000). (9) The bus selection methodology in Attachment 1 defines a single bus location as including any bus Elements at the same voltage level within the same physical location sharing a common ground grid. However, there are some substations that have multiple busses at the same voltage level within the same physical location that share a common ground grid, but are not physically connected together.

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	They are either physically isolated from one another, or connected via a normally open tie switch or breaker. In these cases, the above definition does fit this scenario and each bus should be evaluated independently. To address this scenario perhaps the definition should be re-written as follows: A single bus location includes any bus Elements at the same voltage level that are connected together within the same physical location sharing a common ground grid.

Response: (1) Requirements R1 and R2 have been combined (into what is now R1) to address the concerns.

(2) The DMSDT has added BES to Part 4.1 (now Part 3.1), and throughout the standard for consistency. Part 4.1 (now Part 3.1) has been revised.

(3) The DMSDT has added BES to Requirement R8 (now R6), and throughout the standard for consistency.

(4) The DMSDT has added BES to Requirement R9 (now R7), and throughout the standard for consistency.

(5) We have revised the language of Part 13.2 (now Part 12.2) to "Recorded data shall be retrievable for a minimum of 10 calendar days." It is not necessary for an entity to save the data for more than the 10 days specified. Because of the importance and need for expediency in analyzing BES system-wide disturbances, the DMSDT decided that 10 days was a reasonable time frame to have data stored for. Requesters of data will have to be aware of the 10 calendar day requirement.

(6) The wording in Requirement R14 (now R12) was rewritten for clarification. A list with bulleted items is an "Or" list for the bulleted items.

(7) The Generator Owner is listed as an applicable entity in R4 (now R3) to account for the situation where a Generator Owner is responsible for BES Elements beyond a GSU high side breaker; a bus section for example.

(8) The DMSDT believes that the quarter cycle devices mentioned are acceptable for SOE but not for FR data. The additional specifications suggested are too specific for the standard.

(9) It would depend on how the buses are modeled. If the buses are modeled separately, then they should be considered as separate bus locations. The wording in the Step 1 paragraph has been revised.

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Xcel Energy	(1) It appears that a lot of individual requirements are written for something that isn't overly complex. Please consider consolidating R8-R11, or consolidating the technical specs that comprise R5, R11, and R12. (2) In R14, its not clear why the Regional Entity is introduced here. Also, the Regional Entity would take on the burden of tracking corrective action plans, if the recorder isn't restored in the 90 day period. Recommend changing Regional Entity to Reliability Coordinator.
Response: (1) Each of the Requirements mentioned has its own specific reliability objective. Combining these requirements would have requirements with multiple reliability objectives which is contrary to the purpose of a requirement, and could present compliance difficulties. (2) The requirement has been revised. If recording can't be restored within 90 calendar days, then a Corrective Action Plan has to be submitted to the Regional Entity along with a timeline for the restoration. Regional Entity is used because the Regional Entity has an overall view of the BES.	
Entergy Services, Inc.	(1) All SER and FR data requirements should be included as part of a single table and referenced in a single requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation multiple requirements. (2) Similar to 1) above, all DDR data requirements should be included as part of a single table and referenced in a single requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation of multiple requirements. (3) Add "by voltage level" in Requirement R1 so that it reads "Each Transmission Owner shall identify BES bus locations by voltage level for Sequence of Events Recording (SOER) and Fault Recording (FR)." This is consistent with Attachment 1, Step 1 and clarifies that the FR and SOER are only required at that voltage level.

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	(4) In Requirement R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the Requirement. Suggest Requirement R5.1 be reworded to say "A single record or multiple records that include at least one of the following:" (5) Reword Requirement R14 to 'Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 upon the discovery of a failure shall: (a) Restore the recording ability within 120 calendar days; or (b) "If recording ability is not restored within 120 calendar days, demonstrate efforts to correct the unresolved failure." Recommend increasing the allowed repair time by 30 days to allow for non-inventoried repair parts and limited access of repair personnel to such equipment which may be restricted during certain periods of the year.

Response: (1) Each of the Requirements mentioned has its own specific reliability objective. Combining these requirements would have requirements with multiple reliability objectives which is contrary to the purpose of a requirement, and could present compliance difficulties. The Requirements for sequence of events recording and fault recording are sufficiently unique where there can be no violation of multiple Requirements. Note that the proposed definitions for SOER, FR, and DDR have been removed from the standard.

(2) Each of the Requirements mentioned has its own specific reliability objective. Combining these requirements would have requirements with multiple reliability objectives which is contrary to the purpose of a requirement, and could present compliance difficulties. The Requirements for DDR are sufficiently unique where there can be no violation of multiple Requirements.

(3) The DMSDT discussed and decided that the additional language does not add any clarification to the requirement. The DMSDT also combined Requirements R1 and R2 (into what is now R1).

(4) A list with bulleted items is an "Or" list for the bulleted items. "Or" was added between the bullets of Part 5.1 (now Part 4.1) for clarification.

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(5) The intent of Requirement R14 (now R12) was to have an entity restore recording ability within 90 days, but if that 90 day window couldn't be met then a Corrective Action Plan has to be submitted to the Regional Entity along with a timeline for the restoration. The 90 day window is realistic and practical, and compliance should not be burdensome to an entity. The wording was revised for clarification.	
El Paso Electric	(1) In respect to requirement 6.1.4, will entities be required to monitor multiple lines of a major transfer path or only one? (2) In respect to requirement 6.1.5, will one entity owning an HVDC connecting two interconnections be required to monitor both sides of the HVDC element?
Response: **(1) Referring to the response to Question 4 which was based on numerous comments received, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts were updated according to industry input as follows:** • **One or more BES Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission coverage of disturbance monitoring).** **(2) Both ends of HVDC terminals have to be monitored. However, the entity is only required to monitor the end that it owns. Requirement R6 (now R5) has been revised for clarity.**	
CenterPoint Energy Houston Electric	(1) CenterPoint Energy believes the intent of some of the requirements is unclear without the corresponding Rationale box. It is our understanding that auditors may consult the rationale and other information to be placed in the Application Guidelines section; however, auditors must always refer to the requirement language. Therefore, the language of the requirements should clearly explain the intent of the requirement with less reliance on the Rationale boxes. For example;

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	Requirement R13.2 should identify the data retrieved as only the data measured within 10 days preceding a request. Recommend modifying Requirement 13.2 to read “Only recorded data measured and recorded within 10 days prior to a request will be retrievable.” The Rationale box for R13 clarifies the intent of the requirement; however the language should be more specific. (2) The language for requirement R14 should explicitly identify the sub-bullets as an “or”. Furthermore, CenterPoint Energy recommends modifying the second bullet of Requirement R14 to read “If the recording ability cannot be restored within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability.”
Response: (1) Only the language of the requirement is auditable. Rationales and guidelines are included in the standard to provide guidance to entities and auditors alike. The DMSDT has revised the wording of Part 13.2 (now Part 12.2) and provided an example in the guidelines section of the standard. (2) A list with bulleted items is an “Or” list for the bulleted items. “Or” was added between the bullets of Requirement R14 (now R12) for clarification. The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can’t be achieved then a CAP would have to be developed. R14 (now R12) was revised to clarify.	
Public Service Enterprise Group	(1) In R2, to avoid confusion as to what the phrase “BES Elements at the locations established in Requirement R1” means, we recommend that the Attachment 1, Step 1 have this sentence modified with a new parenthetical phrase an the end: “A single bus location includes any bus Elements at the same voltage level within the same physical location sharing a common ground grid (i.e., Elements directly connected to the bus).” In addition, since the only owners of those Elements may be other TOs or GOs, the reference to “shall notify the owners of those Elements” should be clarified. This requirement should be written as follows: “Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the TRANSNISSION OWNERS AND GENERATION OWNERS of those Elements, within 90 calendar days of determination, that the Elements require Sequence of Events Recording (SOER) and Fault Recording (FR).”

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	(2) In R10, the last two bullets should be combined into one: o Under voltage trigger set at no lower than 85% of normal operating voltage for a duration of 5 seconds. (3) The language in R14 should have "either" added to clarify the required actions. In addition, the language in the second bullet "Report the inability to record data" was changed to "Report the inability to restore the recording ability." See below. "Each Transmission Owner and Generation Owner, within 90 calendar days of the discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recoding (DDR) at the bus locations per Requirement R2 and Elements as per Requirement R7, shall EITHER: o Restore the recording ability o Report the inability to restore the recording ability to the Regional Entity along with a Corrective Action plan (CAP) to restore the recording ability.
Response: **(1) The DMSDT has combined R1 and R2(into what is now R1) to help clarify the responsibilities. Based on other commenters' suggestions to revise Attachment 1 Step 1, the language was revised to "For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus."** **(2) The item was corrected as suggested in R10 (now R8).** **(3) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be developed. R14 (now R12) was revised to clarify. The bulleted items were moved to the body of the requirement.**	
PPL NERC Registered Affiliates	(1) It appeared from the 11/19/13 webinar that the R9 obligation for GOs to "have" DDR does not mean that they must own such equipment, and this position was confirmed in the 12/5/13 NAGF outreach meeting. That is, it would do just as well to have an agreement with the TO to fulfill the PRC-002 requirements if and where the TO already has DDR on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002. R9 should have a

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	footnote saying that “This standard defines the ‘what’ of DDR, not the ‘how.’ GOs may install this equipment or, where the TO already has suitable DDR, contract with the TO.” It would be still better to just eliminate GOs from the requirement, however, per our comment to question #3 above. (2) R6 sets DDR applicability criteria based on the “nameplate rating,” but doesn’t say of what. This could be the generator, or the most-limiting component. We believe that applicability should be based on the most-limiting component, since this sets the actual output achievable. The term, “Facility Rating,” as defined in FAC-008 should then be used to avoid confusion. (3) The frequency and Hz/s settings of R10 should have a latch-time criterion, to prevent inadvertent triggering of the DME. We suggest three cycles. (4) R10 calls for DME to be triggered at no lower than 85% of normal voltage with a latch-time of 5 seconds, but the 5-second ride-through requirement of PRC-024 is only +/- 10%, which is also often where V/Hz relays are set. A trigger of 85% voltage x 5 sec may therefore cause DME to miss the action. (5) Triggered (as opposed to continuously-recording) DME needs to have sufficient storage capability to capture a major disturbance and a potentially large number of aftershocks, but we have no way of knowing how many such recordable events may occur, creating a compliance risk. The DMSDT should establish the expected maximum number of recordable events and state it in the standard.
North American Generator Forum - Standards Review Team (NAGF-SRT)	(1) It appeared from the 11/19/13 webinar that the R9 obligation for GO’s to “have” DDR does not mean that they must own such equipment, and this position was confirmed in the 12/5/13 NAGF outreach meeting. That is, it would do just as well to have an agreement with the TO to fulfill the PRC-002 requirements if and where the TO already has DDR on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002. R9 should have a footnote saying that “This standard defines the ‘what’ of DDR, not the ‘how.’ GOs may install this equipment or, where the TO already has suitable DDR, contract with the TO.” It would be still better to just drop GOs from the picture, however, per our

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	comment to question #3 above. Additionally, it is not clear in R9 whether the specification for signal measurements is on a per generating unit basis or if the signals of interest are a per line basis aggregate at generating stations. This determination weighs heavily on Please more clearly specify if the signals of interest are individual unit measurements or plant total measurement (grouped by output circuit, plant total, etc.). the cost and method of implementation where new equipment must be installed. (2) R6 sets DDR applicability criteria based on the "nameplate rating," but doesn't say of what. This could be the generator, or the most-limiting component. We believe that applicability should be based on the most-limiting component, since this sets the actual output achievable. The term, "Facility Rating," as defined in FAC-008 should then be used to avoid confusion. (3) The frequency and Hz/s settings of R10 should have a latch-time criterion, to prevent spurious triggering of the DME. We suggest three cycles. (4) R10 calls for DME to be triggered at no lower than 85% of normal voltage with a latch-time of 5 seconds, but the 5-second ride-through requirement of PRC-024 is only +/- 10%, which is also often where V/Hz relays are set. A trigger of 85% voltage x 5 sec may therefore cause DME to miss the action. (5) Additionally, R10 allows the use of triggered records from equipment installed prior to the effective date of PRC-002-2, but does not specify how many records an entity must be able to produce in the retrievable period specified in R13 as 10 days prior to a request. This specification is crucial to the amount of memory requirements of existing equipment. At the maximum trigger frequency (triggering every 3 minutes), the existing equipment becomes effectively a continuous recorder. For existing equipment with triggered recording capability, how many records are required to be available in the 10 day retrievable record.

Response: (1) The DMSDT agrees that PRC-002-2 does not address "how" the data is captured, but "what" data is recorded. We have added your suggested language to the Rationale Box for Requirement R9 (now R7) with the caveat that the GO is still responsible for providing the data. The data should be provided for individual units greater than or equal to 500

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MVA nameplate (now Part 5.1.1). For plant/facility (now Part 5.1.1) individual generators with gross nameplate ratings greater than or equal to 300 MVA nameplate when the gross plant/facility rating is greater than or equal to 1000 MVA. **(2) Part 6.1.3 (now sub-Part 5.1.1) refers to "Generating resource(s) where:" and the sub-Parts describe the "Gross individual nameplate rating…" of those resources. Because the characteristics of the most limiting component might not affect a generator's response to system conditions, the applicability will remain based on a unit's nameplate MVA rating.** **(3) The frequency sub-Part 10.2 (now sub-part 9.2) does not preclude the use of latching or timing the trigger. The focus of this requirement is on magnitude threshold.** **(4) (5) The undervoltage trigger threshold and timer are intended to capture sustained undervoltage conditions such as fault induced delayed voltage recovery (FIDVR). The DMSDT believes these settings suffice for this purpose. Because the number of recordable events cannot be predicted, the quantity of records cannot be specified. The records of the data required by Requirement R6 (now R5) need to be retrievable for 10 days. An example has been added to the guideline section for R13 (now R11) describing the length of time data is to be retained.**	
Hydro One Networks Inc.	(1) R5.1 Bullet 2- The wording should be changed as follows: "At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder." Because the deployment of Fault Recorders are not required on every BES bus location, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it is occurring more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it. (2) R4.1- More specificity is needed in the requirement. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads - ".... Voltages for each phase of either each line or bus." which could be confusing.

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	(3) R4.2 - Residual current and neutral current are two different things. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This wording should probably be more specific by stating if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the DT). (4) R4.2.1 - Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific. (5) There is an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The DT has mapped this requirement to R14 of PRC-002-2. These two activities are not the same at all since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. In fact preventative maintenance should reduce the failures. R14 of PRC-002-2 requires entities to repair equipment that they know are in a failed state. (6) R13 - this requirement places the RC, RE and/or NERC in the middle of data sharing. There is no requirement in the standard to facilitate entities to partake in data sharing. Is this really the intent? What if adjacent entities need to exchange post-disturbance information? Does that really need to occur via the RC, RE or NERC if an entity cannot directly request necessary data? (7) R8.3 wording is too restrictive. Real and reactive power may not be able to be determined operationally if say a bus is split at the time of an event (or the split is caused by an event). Suggest the DT correct this requirement by perhaps referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions, Real and Reactive Power could be determined. (8) R3, R4, R12, R13, R14 all reference “the bus locations as per Requirement R2” however this requirement is a notification requirement only for Elements not owned by the TO that need DME. These requirements need to reference both R1 and R2 pending changes to R1/R2.

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	(9) The way R2 is worded presently, it sounds like a TO is required to notify itself if it owns BES Elements at the bus locations. The only action in R1 is to identify busses for DME. It should probably be expanded to indicate that after the busses are identified the TO needs to have DME on the Elements that are owned by the same TO. (10) R3, R4, R12, R13, R14: List of locations that need Sequence of Events Recorders and Fault Recorders is identified in R1 and communicated in R2. Suggest replacing reference to R2 with R1 (11) R8,9,10,11 and R13, R14: Suggest changing reference to R7 with R6 (see the comment for R3 and R4 above) (12) Section 1.2 - Evidence Retention: Second sentence states:" For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit." . To avoid confusion we recommend that the DMSDT removes "may ask" and provide further clarification on what evidence needs to be retained and for how long. One approach would be to make a retention period to be "greater or longer of" the period since the last audit or the list below. (13) Section 1.2 - Evidence Retention: To avoid confusion we suggest that the retention period for R1/R2 and R6/R7 is specified as "current version of the list" or "current and previous version of the list". This will avoid confusion associated with the five years retention when the list is produced at a 5 year cycle.

Response: (1) The DMSDT has revised the language as follows: "At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder."

(2) The intention is not to make the standard overly specific. The intent of the Requirements is to lay the foundation for capturing adequate data for event analysis. Bus voltages could be used for all the Elements connected to that bus. Refer to the Rationale Box for additional explanation.

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(3) The DMSDT notes that the requirement is designed to have the entity provide data and the entity has flexibility as to how this is obtained or derived. Use of Residual current and neutral current will provide similar end results. (4) Monitoring is not required on both sides of the transformers. Derived data is acceptable. The Requirement stipulates the determination of electrical quantities. We have added a clarification to the Rationale Box: "For transformers (Part 3.2.1), the data may be from either the high side or the low side of the transformer." (5) PRC-018-1, R6 addresses maintenance and that is not specifically required in PRC-002. The DMSDT is not prescribing a maintenance program in PRC-002 and we are only requiring that a failure of data recording is reported per Requirement R14 (now R12). Because PRC-002-2 addresses "what" data is recorded, it is intended to have PRC-018-1 retired. (6) Because the intent of the standard is to capture BES disturbances, the R13 (now R11) applicable entities will be involved with the necessary data exchange. The standard does not prohibit individual entities from sharing data amongst themselves. (7) Requirement R8 (now R6) and Part 8.3 (now Part 7.3) stipulate that there has to be data to determine Real and Reactive Power. The requirement is not designed to address every possible system configuration and it is recognized that there may be cases where data is not available. The measured voltage and currents will be the basis for explaining any anomalies in MW and MVAR readings. (8) The DMSDT has combined Requirements R1 and R2 (into what is now R1), and revised the wording appropriately. The requirements have been revised to reference BES Elements consistently throughout the standard. (9) The DMSDT has combined Requirements R1 and R2 (into what is now R1), and revised the wording appropriately. (10) The DMSDT has combined Requirements R1 and R2 (into what is now R1), and revised the wording appropriately. (11) Requirement R7 (R6 and R7 have been combined into R5) addresses the Responsible Entity's selection of the "final" list for DDR. (12)The language used is the standard language required by NERC.	

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(13) The DMSDT agrees and has revised the Evidence Retention section. The revision reflects the combination of Requirements R1 and R2 (into what is now R1).	
Southern Company	(1) The requirements of R3, R4, R5 and R12 for SER and FR data should be included as part of a single attachment/ table and R3 should simply reference the table. As structured presently, if an owner fails to include provide data for a single required element, they would be in violation multiple Requirements. (2) Similar to a) above, R8, R9, R10, R11, and R12 for DDR data should be included as part of a single attachment/ table or possibly separate attachments/tables for TOs and GOs and referenced in a single Requirement. As structured presently, if an owner fails to include provide data for a single required element, they would be in violation of multiple Requirements. (3) The inclusion of the word 'either' in R4.1 seems redundant. (4) R10 allows the use of triggered records from equipment installed prior to the effective date of PRC-002-2, but does not specify how many records an entity must be able to produce in the retrievable period specified in R13 as 10 days prior to a request. This specification is crucial to the amount of memory requirements of existing equipment. At the maximum trigger frequency (triggering every 3 minutes), the existing equipment becomes effectively a continuous recorder. For existing equipment with triggered recording capability, how many records are required to be available in the 10 day retrievable record?
Response: **(1) Each of the Requirements mentioned has its own specific reliability objective. Combining these requirements would have requirements with multiple reliability objectives which is contrary to the purpose of a requirement, and could present compliance difficulties. The Requirements for sequence of events recording and fault recording are sufficiently unique where there can be no violation of multiple Requirements. Note that the proposed definitions for SOER, FR, and DDR have been removed from the standard.**	

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(2) Each of the Requirements mentioned has its own specific reliability objective. Combining these requirements would have requirements with multiple reliability objectives which is contrary to the purpose of a requirement, and could present compliance difficulties. The Requirements for dynamic disturbance recording sufficiently unique where there can be no violation of multiple Requirements. **(3) The wording of Part 4.1 (now 3.1) has been revised.** **(4) Because the number of recordable events cannot be predicted, the quantity of records cannot be specified. The records of the data required by Requirement R6 (now R5) need to be retrievable for 10 calendar days. The DMSDT updated Requirement R13 (now R11) to: "Recorded data shall be retrievable for a minimum of 10 calendar days."**	
Bonneville Power Administration	(1) Introduction4. Applicability 4.1 The Responsible Entity is: BPA feels that under this section planning coordinators and reliability coordinators are named as the responsible entities which are later tasked with determining the necessary locations for dynamic disturbance recording equipment. This was one of the primary issues with the previous version of the standard, PRC-018. These entities failed to write such standards and therefore the standard lacked the necessary content for transmission and generation owners to apply. This basis will face similar challenges. Additionally this delineation of the responsible Entity takes authority away from the TOs and GOs to operate their monitoring systems in a way that makes good financial and operational sense for their individual companies. This definition should also be expanded to include Transmission Operators and Generation Operators. (2) Requirements and MeasuresR1. BPA feels the substance of this section is based on the Attachment 1, which is later labeled as Attachment A, so it is on that section that comments shall be provided. The methodology presented in Attachment 1 is overly complex and does not present a sound technical basis for the location of DFRs and SERs. Monitoring locations above 1500MVA are subject to selection based on mathematical manipulation for which no system impact basis is provided. A final step of "engineering judgment" is then applied in order to round out the list. This methodology may not result in consistent or repeatable bus selection for the placement of DFRs and SERs and will be difficult to defend in an audit scenario. This use of an MVA based location criteria is

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	not consistent with other system impact based criteria currently being used within the NERC standards, such as CIP-002-4 & 5, nor with draft versions of the WECC disturbance monitoring standard. (3) R2. BPA feels this requirement places a compliance burden on the Transmission and Generation owners for equipment over which they have no control. TOs and GOs might be responsible for bus identification and notification of other entities with interconnections to those busses but the identification of individual BES elements and the associated compliance burdens should be left to those with operational responsibility for those elements. (4) R3. BPA feels this requirement refers to R2 in the text I believe this reference should be to R1 as R2 does not define bus locations. (5) R4. BPA feels that this requirement needs to be clarified. Specifically, BPA feels that not all line voltages are required if there is no bus (with two lines minimum). (6) R5. BPA feels that in sections 5.1 and 5.2 specific record lengths and sample rates are delineated. The standard goes too far in mandating equipment specification for the Transmissions and Generation owners. The development of equipment specification must be left to the individual owners and operators in order for them to effectively balance cost and operational requirements. (7) R6. BPA feels the responsibility for the sighting of DDRs should be assigned to the Transmission/Generator Operator/Owner not the reliability coordinator. The Operator/Owner must be left to identify BES elements which require dynamic disturbance recording equipment. This may be easily and consistently accomplished through the application of bright line criteria. The criteria provided in 6.1 are insufficient. The criteria do not account for operating voltage or equipment such as series capacitor installations which could contribute to sub synchronous resonant situations. A comprehensive set of bright line criteria for DFRs, SERs, and DDRs must be developed. These criteria should be consistent with similar criteria used in other NERC and industry standards. Any list of

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	locations which is delineated by a Responsible entity must be subject to some adjustment by the affected TO or GO. (8) R7. BPA feels the Transmission/Generation Owner/Operator must be responsible for the identification of locations which require DDRs not the Reliability Coordinator. Only in this manner may the individual TOs and GOs achieve visibility of their own systems. (9) R14. BPA feels the requirement needs to clearly indicate that it is an "OR" distinction between the two bullets. So that one-hour or one-day equipment reporting and corrective action plan is not required at the time of discovery, but rather (as is intended) only after 90 days of failure.

Response: (1) The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the Elements for which dynamic disturbance recording (DDR) is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected.

(2)R1: Refer to the Guideline for the process behind the development of Attachment 1. Three phase short circuit MVA can be directly correlated to the impact of facilities on the BES. The application of sound engineering principles and operational judgment for locations that need to be captured by sequence of events and fault recording ensure compliance. Adequate system coverage can be proven for an audit.

(3) R2: The DMSDT has combined R1 and R2 (into what is now R1) to help clarify the responsibilities.

(4) R3: The DMSDT has combined R1 and R2 (into what is now R1) to help clarify this and the references in other requirements have been corrected.

(5) R4: Requirement R4 (now R3) states that there has to be data to determine the electrical quantities. Refer to the Rationale Box, and Guideline.

(6) R5 (now R4): The DMSDT decided that Parts 5.1 (now Part 4.1) and 5.2 (now 4.2) are required to ensure an adequate quality of data. Based on other comments received, the 50 cycle requirement has been reduced to 30 cycles. Time-stamped pre- and post-trigger fault data aid in the analysis of protection system operations and determination of operation as

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designed. System faults generally occur for a short time period, approximately 1 to 30 cycles; thus, a 30 cycle post-trigger minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30 contiguous cycles post-trigger. A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point-on-wave data for recreating accurate fault conditions. **(7) (8) R6/R7 (R6 and R7 have been combined into R5): The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the Elements for which dynamic disturbance recording is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected. DDR captures a wide-area view, and where dynamic disturbance data recording should be located is more appropriately assigned to the Planning Coordinator or Reliability Coordinator. A Transmission Owner or Generator Owner can always include more Elements to have data recorded.** **(9) R14 (now R12): A list with bulleted items is an “Or” list for the bulleted items. The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can’t be achieved then a CAP would have to be developed. R14 (now R12) was revised to clarify.**	
Idaho Power Company	(1) As related to R5.1, we wonder if there is a need for both bulleted items. We are assuming that these two bulleted items represent an "OR" otherwise they would be listed as two separate Req. Further, if "At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault" is sufficient, why is there an option to capture 50 cycles of data? (2) We also request clarification of R8 to either explicitly allow or not allow the power measurements to be calculated from the voltage and current used in 8.1 & 8.2. (3) In the WECC footprint, we believe Sequence of Events is typically abbreviated SER.

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Response: (1) Part 5.1 (now Part 4.1) was revised to include "Or". The bullets reflect the capabilities of the means of recording that are available. A list with bulleted items is an "Or" list for the bulleted items. The data specifications reflect the capabilities that exist to industry. Based on comments received 50 cycles has been reduced to 30 cycles. **2) Requirement R8 (now R6) states that the electrical quantities in the Parts can be determined which would allow the power measurements to be derived (refer to the Guideline for Requirement R8 (now R6)).** **3) The DMSDT agrees and has revised the acronym throughout the standard. In the standard SER is the acronym for sequence of events recording.**	
American Transmission Company, LLC	ATC recommends the following: (1) Regarding Requirement R2 - Similar to the recommendation for R1, Generator Owners, not just Transmission Owners, should be obligated to identify Elements at BES bus locations established in R1 that require SOER and FR. If any identified Elements are owned by other Generator Owners or Transmission Owners, then the Generator Owner or Transmission Owner should notify the respective owners. ATC recommends revising the R2 wording to, "Each Generator Owner and Transmission Owner shall identify which BES Elements require SOER and FR at the BES bus locations established in Requirement R1." Revise the R2.1 wording to, "Each Generator Owner and Transmission Owner shall determine whether any required Elements are owned by other Generator Owners or Transmission Owners." And finally, revise the R2.2 wording to, "If any required Elements are owned by other Generator Owners or Transmission Owners, then the Generator Owner or Transmission Owner should notify the respective owners of those Elements." (2) Regarding Requirement R3 - This requirement should follow through with the obligations that were prepared for in R2 by requiring SOER and FR for all of the Elements identified in R2, not just selected circuit breakers. ATC recommends revising the R3 wording to, "Each Generator Owner and Transmission Owner shall have SOER and FR for each Element that they own and was identified per Requirement R2."

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Response: (1) The Requirement R1 bus locations are best selected by the Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these locations. Generator Owners do not typically have the necessary case studies of the transmission system. The DMSDT has combined R1 and R2 (into what is now R1) into a single requirement and revised the wording to clarify the intent. (2) The DMSDT has designed requirements R3 (now R2) and R4 (now R3) to implement what is specified in what is now R1--only want sequence of events recording for circuit breakers and not on each Element. Fault recording data is appropriate for Elements identified in R4 (now R3). The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent.	
Reason International, Inc.	(1) Attachment 2 provides a template for standardization of Sequence of Event records. Following the successful implementation of COMTRADE and recognizing the leading role the US BES plays internationally, it would be more beneficial to all parties involved if the template was based on C37.239-2010 COMFEDE, avoiding multiple templates for SOE records in several countries.
Response: (1) The DMSDT discussed and decided on the .CSV format as being universally acceptable to industry. The .CSV format was selected to ensure uniformity in data collected.	
City of Austin dba Austin Energy	(1) City of Austin dba Austin Energy (AE) believes that the proposed PRC-002-2 standard is overly prescriptive and provides unnecessary requirements that are already addressed by Regional rules, guidelines, requirements, etc. For example, ERCOT has requirements for installing Disturbance Monitoring Equipment (DME) that may address more specific regional needs, considering ERCOT system characteristics. Additionally, AE believes the standard, as proposed, would be costly to implement.
Response: (1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:	

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“Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed. A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices.” Project 2007-11 – Disturbance Monitoring was initiated to address the existing PRC-002-1 “fill in the blank” standard. FERC did not approve or remand PRC-002-1 in its Order No. 693 (March 16, 2007) because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the “fill in the blank” aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). The consolidation of these two Standards will result in a Standard that fully addresses what is necessary to capture power system disturbance data. PRC-002-2 addresses the recording (data), not “how” the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data. The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events. The CEAP postings gave the opportunity to provide cost input.	
Exelon Companies	(1) Comments on R3: R3 states that circuit breaker position must be monitored for identified breakers. In our companies standard design, we connect circuit breaker auxiliary contacts to relays that include monitoring. However, this requirement will present a significant burden since a database must be created to cross-reference prints to prove that hundreds of breaker auxiliary contacts are connected to satisfy compliance requirements. Since three phase currents are to be monitored under the proposed Requirement3, this information can be used to determine circuit breaker status in lieu

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	of monitoring a 52 contact. With three phase current values available, it is not difficult to figure out when breakers were opened based on loss of current and is actually more accurate than breaker auxiliary contacts. It is very straight forward to figure out when breakers are opened based on loss of current for a straight bus configuration. If a single circuit breaker in a ring bus or similar configuration opens for some reason and flow is not interrupted the sequence of breaker openings can still be determined using currents. It is also not necessary to know exactly when a breaker in a ring bus opens if flows in the ring are merely rerouted. Thus, a detailed sequence of events timeline of a power system disturbance can be determined without the use of a circuit breaker contact. In rare cases connection of a circuit breaker contact may have been mistakenly excluded from the protection design. In this case, complying with the standard as written could require installing 1000 feet or more of control cable in an EHV switchyard, incurring a high cost for very little gain. Thus, we believe the DMSDT should eliminate this requirement as it just creates a significant burden, potentially adds cost, provides no commensurate increase in reliability, and is not necessary for events analysis when three phase currents are already required. (2) Comments on R4: It is a natural progression for a TO to upgrade BES lines before upgrading BES transformers since BES lines are subject to many more faults and operations. Thus, modernizing BES lines first has the greatest impact on reliability. For example, a large % of our comapies T-lines employ modern relays with FR and SOER capability and the remaining lines will have this capability shortly. These upgrades are being done on previously determined schedules and include all 138 kV and above lines. The percentage of BES Transformers with modern equipment is much less (15-20%) and upgrades are typically only done when transformers infrequently fail or when protective equipment is obsolete and problematic. Although R4 does state that the TO/GO shall have fault recording necessary to determine required quantities (transformer information can be determined from monitored line data as needed), the DMSDT should consider revising the guidance section of R4 to state that it is adequate to monitor lines and use their fault recordings to determine transformer quantities. The DMSDT should also consider just eliminating R4.2.1. Monitoring lines is much more important and provides information to determine flows in transformers. This would also recognize that the natural progression of system upgrades is to concentrate on the most exposed and

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	problematic areas (T-lines). The number of transformers with increased monitoring is increasing sufficiently already and monitoring of transformers inherently benefits from the rapidly increasing level of monitoring on transmission lines. (3) Comments on R5: R5.3 states that trigger settings need to include Neutral (residual) overcurrent and phase undervoltage. RFC had a disturbance monitoring standard for a few years that we worked diligently to comply with. It required triggering on one or more of various quantities including negative sequence current, negative sequence voltage, residual current, undervoltage, overvoltage, or overcurrent. ComEd met this requirement in hundreds of devices by triggering on residual current (for grd faults), phase overcurrent (for multi-phase faults), and pickup of any forward or backward (if used) phase distance zone (for multi-phase faults). Undervoltage elements weren't always available. The DMSDT should consider modifying this requirement to allow phase undervoltage or phase overcurrent as a trigger for multi-phase faults. Having to tweak hundreds of relay settings (an arduous and expensive process) to meet a NERC standard that is slightly different than the RFC standard just doesn't seem right. There is a good argument that once a system is highly monitored, triggering an event record when the relay trips provides sufficient information for events analysis. We do not believe that a standard specifying what to trigger on is necessary at all for a highly monitored system. Having to go back and change event trigger equations on a highly monitored system is purely burden to the registered entity with no commensurate increase in reliability or increased capability to analyze disturbances.

Response: (1) Regarding currents, currents may reach zero without a breaker opening. The DMSDT contends that breaker position status data is necessary for disturbance analysis.

(2) R4 (now R3): The Purpose of the standard is "To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances." . Capturing transmission line and transformer data is necessary to achieve this goal. The requirement allows the entity to "determine…electrical quantities." As long as you have sufficient FR data available to determine the electrical quantities specified under the requirement, you do not have to monitor every element.

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(3) R5 (now R4): The DMSDT has revised sub-Part 5.3.2 (now sub-Part 4.3.2) to allow for overcurrent: sub-Part 5.3.2 (now sub-Part 4.3.2) reads: "Phase undervoltage or overcurrent."	
Florida Municipal Power Agency	(1) FMPA does not believe that a standard is justified for Disturbance Monitoring, as such, we believe that disturbance monitoring is better addressed through guidelines than through a standard, as further discussed below. In the scheme of things, disturbance monitoring provides very little value to operating the bulk-power system reliably as compared to other standards. Establishing SOLs and operating to them; coordinating and maintaining effective protection systems; maintaining supply/demand balance and frequency; cyber security; and effective and trained human resources are greater than one quantum step more important to reliable operations than equipment installed simply to ease the ability to perform post-mortem analyses on events and to validate stability modeling that cannot be that accurate in the first place simply due to Chaos Theory (e.g., the Butterfly Effect) and the inability to predict the future accurately. While installing DMEs may be good / prudent action, FMPA believes it is imperative to avoid a mode of thought that seems to prevail among many within our industry, and that is a mode of thought that if something is good for reliability, then we need to write a standard for it. Such mode of thought is counterproductive and stunts creative improvement because it creates a perverse incentive to only do the minimum to meet the existing standards due to the danger of better performance causing an increased level of governmental regulation. Governmental regulation should be to minimum requirements while not stunting the creativity of the industry to perform better than required, and FPA Section 215 is crafted with that thought in mind:"The term `bulk-power system' means--`(A) facilities and control systems NECESSARY FOR OPERATING an interconnected electric energy transmission network ..." (emphasis added)"The term `reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system."While DMEs may be good/prudent, they are not necessary to provide reliable operation of the bulk-power system. In addition to a lack of technical justification, a standard that requires DMEs is also not justified from a cost/benefit perspective. The benefit of DMEs as stated in the purpose of the draft standard are to assist in post-mortem analyses of events. We have been doing event analyses for decades without the standard. Yes, they may take

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	longer to perform do to the difficulty in establishing a sequence of events post-mortem and other challenges, but, we were able to do it. So, the benefit of a DME is to shorten the time and effort it takes to do a post-mortem (what is that, maybe three or four person-years, maybe a million?) compared to a cost of installing these devices and maintaining them on hundreds of buses (maybe $10's of millions) for events that may happen once in 10-20 years close enough to a DME to matter.In addition, the system has changed a lot over the last 10 years since the Northeast Blackout of 2003 and we can gain much more information now from microprocessor based relays prevalent throughout the system and phaser measurement units (PMUs) also installed throughout the system. Additionally, the effort does not justify the compliance administration costs at both the entities and at NERC and the Regions for administering compliance to this proposed standard. The standard as written is complicated, long, has many requirements, and in general is far too complicated and onerous in relation to its minimal reliability benefit. Also, how would such a proposed standard impact compliance with PRC-006, EOP-004 and other standards that require post-mortem event analyses?In conclusion, FMPA believes that a standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.

Response: (1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:

"Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.
A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices."

Project 2007-11 – Disturbance Monitoring was initiated to address the existing PRC-002-1 "fill in the blank" standard. FERC did not approve or remand PRC-002-1 in its Order No. 693 (March 16, 2007) because the standard contained requirements that

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applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the "fill in the blank" aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). The consolidation of these two Standards will result in a Standard that fully addresses what is necessary to capture power system disturbance data. PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data. The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.	
Nebraska Public Power District (NPPD)	(1) For clarification on R2 after receiving notification from a TO that FR or SOER may be required how long does the receiving entity have to install the appropriate recording device? Please clarify if it is still 4 years to be 100% compliant? (2) R3 can we clarify the circuit breakers that are not connected to lines and transformers designated in R4 are not required to be part of the SOER? For example, do not require SOER for a 115kV circuit breaker on a 115/34.5kV load serving transformer. (3) R4 M4 states that "Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations." For individual relays used as recorders this may encompass a significant amount of data. Consider allowing evidence to be a single design standard or common general design example to be allowed as evidence rather

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	than requiring all the detail data from every location which could be hundreds of relays with settings/drawings/records for example. There is a similar concern for R3 M3 evidence. (4) R5 5.1 states: A single record or multiple records that include: o A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. Consider using 30 cycles instead of 50 cycles for post records since faults typically should be clearing faster (less than 10 cycles on most critical high voltage lines). This may reduce the risk of memory record overwrite in relays that are of older vintage. DDR capabilities will also most likely be installed in the most critical areas for longer recording needs. (5) R5 5.3.2 lists a required trigger setting for phase under voltage. Many relays used for FR will use the phase impedance zone reaches to trigger records. This can clearly define the reach for data to be triggered where defining an under voltage may be more difficult to control the reach. There is some concern with overwriting data in the relays with settings that are less intuitive for controlling how often a device may trigger. I strongly recommend allowing phase under voltage or phase distance reaches for 5.3.2 as trigger points. Generally the trigger requirements appear logical. There is some concern that these recording devices are not perfect and devices that appear to be functioning correctly will occasionally not trigger as set. These are not perfect devices. Is there a risk for non-compliance for devices that are set to meet compliance yet do not trigger correctly? This seems like an unnecessary risk. (6) R8 8.1 seems to be a bit confusing. R8 8.1 allows a single phase to neutral voltage yet 8.3 appears to require all voltages. R8 8.2 is also similar in nature. Can this be changed to require one voltage and one current on the same phase? (7) R11 states “11.2. Output recording rate of electrical quantities of at least 30 times per second.”Please clarify to make sure this can be clearly understood by an audit or enforcement team as well as owners. Is this processing speed or DSP of a device? For example some relays state “AC

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	voltage and current inputs 8000 samples per second, 3 dB low-pass analog filter cut-off frequency of 3000 Hz" or "protection and control processing 8 times per power system cycle". Are these examples what is asked for with 11.2? Most devices are likely to meet this rate. Does it really need to be in the standard? This seems excessive. Any options to reduce the requirements in this standard would help to limit the complexity and data to manage. (8) R13 states: "13.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request."This is a good goal to shoot far however data can be overwritten in relaying devices with the best intentions when numerous operations and voltage levels are used to trigger events. I don't feel that the ability to guarantee data is available for this time period is fully under the control of the person setting the pickup and triggering in the device 100% of the time. This should not be a finable enforceable requirement and should be removed. On occasion failing equipment can provide such great amounts of data as to overwrite memories in relaying equipment. (9) R13.4 states "Fault Recording and Dynamic Disturbance Recording data will be provided in electronic C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files." Can the statement be added that if the device is not capable of providing COMTRADE files directly then it is acceptable to provide the data in its native format? I am concerned with the need to reformat data could risk loss of data before it may ever get to an analysis team. Some formats may not be easily convertible in older devices. Consider adding: Data content requirements and guidelines shall be in accordance with R13.3, R13.4 and R13.5 or other formats deemed acceptable by the requesting regional entity. (10) R14 requires the tracking of recording failures and restoration. I recommend this only be required for recording devices not under another maintenance plan. For protective relays performing recording functions they should not be under this requirement if they are covered under PRC-005

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	which is a stringent maintenance plan that will be in place. This will reduce additional tracking requirements and burden.

Response: (1) The standard does not specify installing a recording device, but have recording capability. The DMSDT also has combined Requirements R1 and R2 (into what is now R1). The Implementation Plan was revised and lists 100% completion for Requirements R3 (now R2), R4 (now R3), and R5 (now R4) in 6 years after the notification of the list. After the 5 year reassessment required under R1, entities have 3 years following notification to comply.

(2) Requirement R3 (now R2) dictates that SER is required for all circuit breakers connected to the BES buses identified in the original Requirement R2 (note that Requirements R1 and R2 have been combined into what is now R1). In the example given, if the 115kV side of the transformer is connected to a BES bus through a circuit breaker, then that breaker must be captured by SER. R3 (now R2) has been revised to read:

> **R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker they own connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses identified in Requirement R1. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]**

(3) The DMSDT agrees and has added "including a single design standard as a representation for common installations" to the measures for M3 (now M2) and M4 (now M3).

(4) System faults generally occur for a short time period, approximately 1 to 30 cycles; thus, a 30 cycle post-trigger minimum record length is adequate. Responding to comments received, the 50 cycle requirement has been reduced to 30 cycles.

(5) The DMSDT has revised Part 5.3.2 (now 4.3.2) to include "overcurrent". If data is not captured that should have been captured, then Requirement R14 (now R12) regarding data recording failure would have to be followed.

(6) Requirement R8 (now R6) Part 8.1 (now Part 7.1) stipulates "One phase-to-neutral or positive sequence voltage." Requirement R8 (now R6) says "to determine". Three phase Real Power and Reactive Power flows can be determined from the single phase voltage and current values. Sufficient measurements must be made to accurately provide real and reactive power on a three phase basis. Requirement R8 (now R6) does read single phase quantities. Dynamic

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Disturbance Recording is used for measurement of transient response to system disturbances, during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. **(7) Regarding Part 11.2 (now Part 10.2), refer to the Rationale Box. The DMSDT believes that this information needs to be specified in the standard in order to meet the needs for disturbance monitoring. While most devices meet the requirements, the DMSDT had to ensure that for consistency all recording capabilities would be addressed.** **(8) For clarity, the language of Part 13.2 (now Part 12.2) was revised to: 12.2 "Recorded data shall be retrievable for a minimum of 10 calendar days."** **(9) Part 13.4 (now Part 12.4) is necessary to specify the format because for past significant wide-area system events the data was not available in a consistent format, and that presented problems to the analysis of the event.** **(10) Requirement R14 (now R12) deals with sequence of events recording, fault recording, and dynamic disturbance recording failure, and the response to its failure. Any documentation, even if under another plan, would be acceptable.**	
Oncor Electric Delivery	(1) General: Oncor identified several instances where the Rationale Boxes provided much needed clarity to the Requirement itself. It is understood the Rationale Boxes will be retained but relocated to the Application Guidelines Section of the Standard. However, incorporating the Rationale/intent language into the Requirement itself would further clarify the Requirements resulting in a clear and mutual understanding for both the Registered Entity and the auditor(s). Therefore Oncor recommends the Standard DMSDT review the Requirement language and the corresponding relocated Rationale language to ensure there are no gaps once moved to final state. Additional details provided below. (2) R1: To clarify the line/bus distinction, Attachment "BES Sketches - Facility Example & Boundary Definitions" should be added to the Standard.

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	(3) R2 and R6.2: The Implementation Plan includes specific references to time frames for becoming fully compliant with the locations lists, but the Requirement language itself does not include post-implementation compliance timelines for the required reassessments. The Implementation Plan states "Entities shall be 100% compliant with a reassessed list from Requirement R1, Part 1.2 or R6, Part 6.2 within three (3) years following notification of the list." This language should also be included in the language of the affected Requirements to prevent any disparity following the initial implementation and departure from the Implementation Plan. (4) R3: Legacy FR equipment installed before the standard effective date may not be capable of embedded SOER. R3 does not afford the same caveat for older equipment where SOER is required that R10 provides for older equipment where DDR is required. Language should be added to R3 providing the option to utilize FR digitals to monitor circuit breaker position for each circuit breaker. (5) R4 and R8: Add Rationale box stipulation that the required “electrical quantities, whether directly measured or derived,” to R4 and R8 as described below: The R4 Rationale Box explains the method of deriving electrical quantities; however, the requirement language of R4.1 does not reflect the intent described in the Rationale Box. Specifically, whether or not locations where busses are effectively tied together, such as on ring or breaker-and-half bus configurations, can derive the required phase-to-neutral voltages by monitoring a minimum of two of each phase-to-neutral voltages, from either line terminal or bus potentials. In a typical large switching station, this could eliminate costly retrofits to literally provide all three phase-neutral voltages for “each line or bus.”The language of R8.3 does not specify the method used to provide “Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.” If the intent follows the electrical quantity collection of R4, the language of R8 should also specify the ability to derive electrical quantities. Allowing calculated power flow would prevent costly retrofits to literally provide 6 dedicated analog traces for each Element required to have a DDR.

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	(6) R10: The language of R10 could be interpreted to mean the triggering requirements are only applicable to DDR equipment installed prior to the effective date of the standard. The triggering requirements are applicable to all DDR equipment. Additionally, the collection of 3-minute FR records for every transient event as a substitute for a DDR is a costly modem transfer and storage retention practice. (7) R11: If relays meet the requirement of a DDR, the language of R11.1 or M11 should specify that synchrophasor data is acceptable for DDR analysis. (8) R12: The language of R12 should provide a caveat to allow for manipulating event records to UTC for equipment that is synchronized but cannot time-stamp with UTC as the reference. This would be similar to the “or derived” language suggestions to Requirements R4 and R8 which would allow for legacy equipment to meet the standard as well as allow for the time-alignment for multiple FR/SOERs as M12 evidence. Additionally, Rationale box language, further explaining the UTC local offset, should be included in M12 to clarify that offset records are acceptable as evidence. In other words, requested records must be supplied in UTC format, but the stored format does not need to adhere to UTC format. (9) R13: Some entities do not automatically name files in the COMNAME fo`rmat for ease of data storage. With the phrase “formatted records,” M13 implies that manipulation of file before submittal is allowed. If data file names can be changed to the prescribed COMNAME formatting, R13.5 should specify that the data files need only be provided in this format rather than originally named this way.

Response: (1) The DMSDT has reviewed the Requirements versus the Rationale Boxes. The content of the Rationale Boxes answer the question “why?”. The DMSDT has reviewed the requirements and Rationale Boxes and revised accordingly taking into account stakeholder comments.

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(2) Requirements R1 and R2 have been combined (into what is now R1) for clarification in response to comments received. The wording in what is now R1 was clarified. (3) The DMSDT has made the Implementation Plan and standard time frame consistent. (4) Regarding legacy equipment for sequence of events recording, the standard is not about equipment, just the data that is recorded. It is not the "how", but "what". The requirement was revised to clarify that it is the data that is required. (5) Requirements R4 (now R3) and R8 (now R6) do allow an entity "to determine", determine includes calculate. This is specific language used in a requirement. The R4 (now R3) and R8 (now R6) Rationale Boxes have been revised. (6) The dynamic disturbance recording triggering specified in Requirement R10 (now R8) deals with non-continuous recorders installed prior to the effective date of the standard. Otherwise, dynamic disturbance recording must be continuous. The three minute record applies to dynamic disturbance recording and not fault recording. (7) Regarding Requirement R11 (now R9), the standard is not about the "how" of capturing data, but "what" data is captured. If the data provided meets the requirements for recording, then that data can be used. For example, synchrophasor data would most likely meet the requirement of dynamic disturbance recording data. (8) Data provided must be time synchronized to UTC, with or without local time offset. The DMSDT added the following to the Rationale Box for R12 (now R10): Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset. (9) Part 13.5 (now Part 12.5) stipulates that file names provided to the requesting entities are to be provided in COMNAME format. The standard is intentionally silent on what the file name should be prior to that.	
Northern California Power Agency	I support the comments of FMPA from Frank Gaffney
Response: Please see the DMSDT response to FMPA.	

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American Electric Power	(1) In general, we believe the standard is written to prescriptively when the standard emphasizes post-event analysis. More clarity is needed regarding time frame, etc. as to what is expected of a TO after they informed that data recording is required for an element owed by the TO. (2) R13.1: Suggest "The recorded data will be provided within 30 calendar days, or other agreed-upon time frame, of a request." (3) It appears that R2 applies to shared stations only. If this is accurate, we suggest rewording to clarify the intended applicability. In addition, it is unclear which entity would be responsible for the installations. (4) The wording in R13.2 is unclear. Possible interpretations include that the data must be retrievable for at least 10 days at any given time, or that the data must be retrievable on a continuous basis. Please revise to provide clarification. (5) The sub-bullets listed in R13, especially R13.2, would be more appropriately included in the technical requirements of each DME type in R3, R5 and R11. (6) The sub-bullets in R14 read do not clearly read as an OR statement and may be misinterpreted as an AND statement. We recommend removing the bullets and making the item read as a single sentence: "... shall restore the recording ability or report the inability to record data..." (7) R3 requires GOs and TOs to install SOER for each circuit breaker they own that is connected to the bus locations identified in R1. This does not account for the fact that not all of the circuit breakers on the identified busses should require SOER because some breakers may be associated with non BES equipment.

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	(8) R4.1 should be modified to state “Phase-to-neutral voltages for each phase of either each specified line or bus.” (9) In R5.1, an “or” should be added to the end of the first bullet to improve clarity. (10) Also, in R5.3 the word “settings” should be removed to improve technical accuracy. (11) In R7, the word “determination” should be replaced with “identification” to be consistent with the rest of the standard. (12) R8 should be revised as follows to improve clarity:R8.1: “At least one phase...”R8.2: “The current on the same phase as the voltage in...”R8.4: “Frequency of at least one of the.... (13) R9 should be revised as follows to improve clarity:R9.1: “At least one phase...” (14) R9.2: “The phase current on the same phase as the voltage in...”The DMSDT may want consider combining requirements that are related to the same monitoring equipment types. (15) R4 and R5 could be combined because they both relate to specifications of FR equipment. Similarly, R8, R10, and R11 could be combined, as they all relate to DDR equipment.

Response: (1) The time frames for each requirement are specified in the Implementation Plan.

(2) To ensure the expeditious and uniform submission of data, a time frame has to be specified. The 30 days specified in Part 13.1 (now Part 12.1) is a reasonable amount of time to respond to a request.

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(3) Requirement R2 (now R1) is not intended to apply to shared stations only. The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent. The standard does not address installations, only data. (4) Part 13.2 (now 12.2) has been revised to clarify the time frame for providing data. "Recorded data shall be retrievable for a minimum of 10 calendar days". (5) Because of applicability of the Parts of Requirement R13 (now R11), they will be kept under one central requirement. (6) Requirement R14 (now R12) has been revised to reflect the comments received. (7) Requirement R3 (now R2) dictates that SER data is required for all circuit breakers connected to the buses identified in Requirement R2 (the DMSDT has combined Requirements R1 and R2 into what is now R1). Requirement R3 (now R2) has been revised to read: R2: Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker they own connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses identified in Requirement R1. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] (8) The DMSDT made a revision in the wording for Part 4.1 (now Part 3.1), and it includes "specified". (9) A list with bulleted items is an "Or" list for the bulleted items. "Or" will be added between the bullets of Part 5.1 (now part 4.1) for clarification. (10) The DMSDT does not feel that removing "settings" from Part 5.3 (now Part 4.3) would improve its technical accuracy. (11) "Determination" was changed to "identify" in Requirement R7 (now R5). (12) R8 is now R6. The DMSDT retained the original language in Part 8.1 (now Part 6.1) and 8.4 (now Part 6.4). Part 8.2 (now 6.2) was revised. (13) R9 is now R7. The DMSDT retained the original concept.	

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(14) Requirement R8 (now R6) applies to the Transmission Owner; Requirement R9 (now R7) applies to the Generator Owner. Because of the differences in the requirements for each entity, those requirements will remain separate. **(15) The DMSDT does not agree with this comment. Each requirement applies to different entities and/or data requirements.**	
Wisconsin Electric Power Company	(1) In Requirement 14, there is a discrepancy between the text of R14 and the Rationale statement which follows. The bullet “Restore the recording capability” should be changed to “Restore the recording capability if possible”. This will allow the entity more time if necessary to correct the problem, which is allowable as described in the Rationale. As it stands, an entity will be in violation if the recording capability is not restored within 90 days of discovery of a failure.
Response: (1) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can’t be achieved then a CAP would have to be developed. R14 (now R12) and its Rationale Box have been revised.	
JEA	(1) It is unclear if both of the two statements in R5.5.1 are required, or if meeting only one of the two is sufficient.
Response: (1) The bullets reflect the capabilities of the means of recording that are available to industry. A list with bulleted items is an “Or” list for the bulleted items. “Or” will be added between the bullets of Part 5.1 (now 4.1) for clarification. Both bullets of 5.1 (now 4.1) are needed to address the Fault Recording that is available to industry.	

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AESI Acumen Engineered Solutions International Inc.	(1) It is understood that the intent of this version 2 of the PRC-002 Standard is to ensure that sufficient recording capability exists without being prescriptive as to the type of equipment that must be installed to meet the recording capability requirements. It is also understood that the DMSDT did not wish to be unnecessarily prescriptive with respect to periodic maintenance activities, and as such, this version 2 of PRC-002 contains no such requirement. It does not appear however that the Standard would necessarily ensure that Entities continue to have the required recording capability over time following initial installation and commissioning and after completion of the Implementation Plan. Although an Entity should be compliant at all times, is it plausible that an Entity could be unaware if some of the required recording capability is deficient or no longer exists? Disturbances do not occur very frequently, and an Entity may not become aware of deficiencies for many months or years until a disturbance occurs, when the disturbance data is requested; at which point they realize that the disturbance recording functions or capability is deficient in some manner. It could be argued that verifying compliance, and ensuring that the required recording capability exists, is the task of the auditor; however, this is dependent upon the Standard being included in an audit, and an audit itself may only occur once every 3-6 years. We suggest that the DMSDT consider adding a requirement for Entities to simply perform a periodic verification of the required recording capability, without specifying how to verify such recording capability, on an interval to be determined by the DMSDT. There are many mechanisms available for verification such as downloading recorded data, performing equipment self-tests, etc. Allowing Entities to perform periodic verification of the required recording capability in a manner they choose is consistent with the spirit of the Standard of not being unnecessarily prescriptive, and is consistent with ensuring that the required recording capability is in place.

Response: (1) The DMSDT considered the comment and determined that the addition of such a requirement would not improve the reliability of the BES without placing an undue burden on the responsible entities. With regard to maintenance, because the standard just deals with data, the DMSDT decided not to go further than Requirement R14 (now

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R12). It is understood that a data capture failure may only be exposed during a system disturbance, but with the extent of data capture mandated by this standard "normal" data failures can be tolerated.	
Modeling Working Group	(1) MWG finds that requirements for data retention are essential to this standard but are missing in the current draft. MWG recommends including a requirement that all triggered data recordings be retained for a minimum of 2 years and that all continuous data recordings be retained for a minimum of 30 days. MWG also recommends including a requirement that all continuous data recordings be scanned against the set of triggers defined in R10 and those portions of the continuous recordings that fall within the time periods defined by those triggers be retained for a minimum of 2 years.
Response: (1) The retention periods are specified in Requirement R13 (now R11). They were decided upon because the DMSDT felt that the data to analyze a significant system event would be called for quickly. Requesters of data also have to be aware of the retention requirements in the standard. Retention specifications beyond this "initial" data gathering are outside the scope of this standard. The DMSDT notes that this is a disturbance monitoring standard and that model verification is outside the scope of this standard.	
Dominion	(1) PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01).

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	(2) Dominion believes the intent of Requirement R2 is for Transmission Owners to notify "other" owners of BES Elements, as explained in the Rationale statement. The requirement as written would also require the Transmission Owner to notify itself. Therefore, Dominion suggests revising R2 and M2 as follows: R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the "other" owners of those Elements...M2. The Transmission Owner has dated evidence (electronic or hard copy) of notification to "other" owners of Elements... (3) In R1.2 and R 6.2, what prevents a TO or RE from assessing the locations and elements on too frequent of a time basis. As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability in where monitoring is really needed. Frequent assessments could jockey locations above and below the minimum criteria line and create confusion. (4) In R2, it infers that the TO as part of R1 developed a list of Elements, however R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest R2 be reworded to say "Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify...". If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. (5) In R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the requirement. We suggest R5.1 be reworded to say "A single record or multiple records that include at least one of the following:". (6) In R14, reword to indicate that the second bullet is only applicable if the first bullet is not completed within 90 days. We suggest this wording for the second bullet - "If recording ability is not restored within 90 days, report the inability..."

Response: (1) The DMSDT is aware that the NPCC DMSDT has been reconvened to review the Regional Standard with respect to PRC-002-2 after it is approved.

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(2) The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent. **(3) There is nothing that prevents a TO or RE from a too frequent assessment. The DMSDT does not believe that reassessment will result in a significantly different set of buses or elements for which data is required unless significant construction activity or reclassification of BES elements has occurred. If an entity is notified that they have a data obligation, the implementation plan for PRC-002 allows them three years to become compliant.** **(4) The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent.** **(5) The bullets reflect the capabilities of the means of recording that are available. A list with bulleted items is an "Or" list for the bulleted items. "Or" was added between the bullets of Requirement R5 (now R4) for clarification.** **(6) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be developed. R14 (now R12) and its Rationale Box have been revised to clarify. Requirement R14 (now R12) was revised to include "Or". The bulleted items were moved into the requirement wording.**	
New York Power Authority	(1) R10It is stated that triggered records from existing equipment can be accepted in lieu of continuous recording if the triggered records meet the criteria in 10.1 and 10.2. If continuous recording is available and meet all criteria, are triggered DDR records required? (2) R13.3There is no need to require this data to be written in CSV format. Tab delimited text would work as well and would not limit the use of commas in descriptors or other entries. The format described in Attachment 2 is limiting and incomplete (see comments on Attachment 2). (3) R13.4This requires that Fault Recording and Disturbance Recording data will be provided in COMTRADE (C37.111) formatted files, but does not specify a revision level or year for the COMTRADE standard. The requirement should specify "C37.111-2013 or later" in order to require a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.

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	(4) Attachment 2The format in Attachment 2 is limited and incomplete. While the information required is obviously necessary, the format limits or omits information available from some SOERs. R13.3 states that the files must be comma-delimited, but Attachment 2 makes no statement about the length of any string or value. There is no provision for SOERs which may have detailed descriptors of the contacts being monitored but may be a single string. “Local Time Offset from UTC” should be expressed in hours before or after UTC rather than letter designations. There is no provision for acceptable terms for “State” except for “OPEN “and “CLOSE”. Other terms may be more appropriate for some devices monitored by an SOER, such as “ENABLED” or “DISABLED”, “ON” or “OFF”, etc. In short, Attachment 2 appears to be an attempt at defining a standard but does not adequately define a format. Development of such a standard may be better left to an IEEE Working Group or other entity.
Response: (1) Triggered DDR records would not be required if continuous recording is available. **(2) The DMSDT discussed and decided on the .CSV format as being universally acceptable to industry. The .CSV format was selected to ensure uniformity in data collected.** **(3) The DMSDT agrees and has made the revision to R13 (now R11) as suggested.** **(4) The intent of Attachment 2 was to show only what would be minimally required. There is nothing to prevent the inclusion of additional data. It is not intended to have any string or value length on Attachment 2. The “Local Time Offset from UTC” column heading has been revised to reflect hours before or after UTC. The footnote for the “State” column has been revised to indicate that “OPEN” or “CLOSE” must be used for circuit breakers to be consistent with Requirement R3 (now R2), and a note added that other status monitoring indication can be used for devices other than circuit breakers.**	
Lincoln Electric System	(1) R13.2 specifies that “The recorded data will be retrievable for the period of 10 calendar days preceding a request”. As drafted, this requirement seems to indicate that if an event happened on June 1st and the data was requested on June 30th, then the data would have to be retrievable from June 20th to the 30th. However, if a request is made on June 6th following a June 1st disturbance, it would not be possible to comply with the 10 calendar day requirement.Unless LES

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	misunderstands the DMSDT's intent, it seems as though the requirement is meant to ensure that data is available and retrievable for a period of 10 calendar days following a disturbance in the event further analysis needs to be conducted. To ensure this intent is conveyed, LES recommends rewording R13.2 to indicate that the 10 day period starts at the time of the event. Additionally, R13.2 should also account for circumstances beyond the control of the TO or GO in which multiple events caused the relays recording the data to overwrite it with more recent events due to limited memory space. As an example, a TO could have information available for the 10 days required by the standard, but multiple disturbances due to severe weather on day 12 resulted in initial data being unavailable for a request initiated on day 12 or later. If this occurs, R13.2 would then place the Transmission Owner or Generator Owner in violation of the standard due to a limitation inherent to the relay.13.2. The recorded data will be retrievable for the period of 10 calendar days following a disturbance.(1) Footnote (1): The 10 calendar day period may be waived for circumstances beyond the control of an applicable Transmission Owner or an applicable Generator Owner, such as, but not limited to, equipment manufacturer limitations resulting in the loss of data.
Response: (1) Requirement R13 (now R11) stipulates the expectations of a Transmission Owner after being notified data is required. Specific time frames need to be specified in the Requirement to ensure the expeditious treatment of data. Part 13.2 (now Part 12.2) has been revised to clarify the time frame for providing data. The language of Part 13.2 (now Part 12.2) has been revised to "Recorded data shall be retrievable for a minimum of 10 calendar days." Because of the importance and need for expediency in analyzing BES system-wide disturbances, the DMSDT decided that 10 days was a reasonable time frame to have data stored for. Requesters of data will also have to be aware of the 10 calendar day requirement.	
Lower Colorado River Authority	(1) R3 - clarify if EMS/RTU or Plant DCS circuit breaker timestamps will meet this requirement. (2) R3, R4, R5, R11, R12, R13, R14 - Clarify "AND" in requirement and "OR" in measure - language is confusing. It is inconsistent.

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	(3) R5 - Change 5.1 minimum length from 50 to 30 cycles. An excessive number of events can cause data to be overwritten and can delay the downloading of data. (4) Change 5.3 to "Trigger settings for at least one of the following:" -OR- remove Phase undervoltage as a trigger requirement. (5) R13 - revise 13.2 from a minimum of 10 calendar days down to 5 calendar days. Longer-term storage of data may be difficult with a large number of SOER/FR/DDRs on your system. (6) R14 - change minimum response time from 90 calendar days to 180 calendar days to allow for design, procurement, and installation of long lead-time equipment/components used for SOER/FR/DDR.
LCRA Transmission Services Corporation	(1) R3 - clarify if EMS/RTU or Plant DCS circuit breaker timestamps will meet this requirement. (2) R3, R4, R5, R11, R12, R13, R14 - Clarify "AND" in requirement and "OR" in measure - language is confusing. It is inconsistent. (3) R5 - Change 5.1 minimum length from 50 to 30 cycles. An excessive number of events can cause data to be overwritten and can delay the downloading of data. (4) Change 5.3 to "Trigger settings for at least one of the following:" -OR- remove Phase undervoltage as a trigger requirement. (5) R13 - revise 13.2 from a minimum of 10 calendar days down to 5 calendar days. Longer-term storage of data may be difficult with a large number of SOER/FR/DDRs on your system. (6) R14 - change minimum response time from 90 calendar days to 180 calendar days to allow for design, procurement, and installation of long lead-time equipment/components used for SOER/FR/DDR.

Response: (1) The standard is not concerned with "how" the data is captured, only "what" data is captured. It is the responsibility of the entity to make this determination.

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(2) "And" is used in the Requirements because the Requirements need to be all encompassing. The Measures are written with "Or" because they are written to address either entity's compliance with a Requirement and the types of evidence required are written as an either/or option. You do not have to have all forms of evidence. (3) In Part 5.1 (now Part 4.1) the 50 cycle requirement has been reduced to 30 cycles. (4) Both Fault Recorder Trigger settings were selected to cover those events involving and not involving ground, and those events that might not have an accompanying significant collapse in voltage. The DMSDT has revised sub-Part 5.3.2 (now 4.3.2) to revise the wording and allow for overcurrent: "4.3.2. Phase undervoltage or overcurrent." (5) The DMSDT considered the data storage necessary, and felt that the 10 days preceding a request was achievable with equipment available. (6) Based on industry comments, 90 days is realistic and practical for determining the availability of data recording capability. The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be developed. R14 (now R12) and its Rationale Box have been revised to clarify. R14 (now R12) is no longer bulleted.	
ITC	(1) R4, R11, R12, R13 and R14 need to be clear that they apply to the Element and/or equipment owner. They will be acceptable if they are reworded as:R4 after "following electrical quantities" insert "for each of the Elements they own"R11 after "for the Elements" insert "they own"R12 and R13 after "Dynamic Disturbance Recording (DDR) data for" insert "for Disturbance Monitoring Equipment they own"R14 after "or Dynamic Disturbance Recording (DDR)" insert "that they own"
Response: (1) The DMSDT has addressed ownership through revisions made to R4 (now R3), R11 (now R9), R12 (now R10), R13 (now R11) and R14 (now R12).	

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Northeast Power Coordinating Council	(1) Regarding Attachment 1:a) The term "BES bus location" is not clear. There could be two or more BES bus locations at the same physical location (substation). The definition of "BES bus" could not be found.b) Step 7 of Attachment 1 does not specify how to round the 10% of the BES bus locations, determined in Step 6, with the highest maximum available calculated three phase short circuit MVA.c) Step 8 of Attachment 1 does not specify how to round the additional 10% of the BES bus locations determined in Step 6.d) Attachment 1 does not specify how to distribute an odd number for 20% of the BES bus locations between b) and c) from above. (2) In Part 1.2 and Part 6.2, what prevents a TO or RE from assessing the locations and elements too frequently? As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability where monitoring is really needed. Frequent assessments could move locations above and below the minimum criteria line and create confusion. (3) We agree with R1, but do not see the need for R2 because through R1 and Attachment 1 each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR). There is not another owner(s) that a TO needs to communicate the list to, unless the "list of BES bus locations that it owns" stated in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that's the case, Step 1 in Attachment 1 needs to be clarified. (4) In R2, it infers that the TO as part of R1 developed a list of Elements, however R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest R2 be reworded to say "Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify...". If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. The intent of Requirement R2 is for Transmission Owners to notify "other" owners of BES Elements, as explained in the Rationale statement. The requirement as written would also require the Transmission Owner to notify itself. Therefore,

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	suggest revising R2 and M2 as follows:R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the “other” owners of those Elements...M2. The Transmission Owner has dated evidence (electronic or hard copy) of notification to “other” owners of Elements... (5) Requirement R3 specifically asks to have SOER, however the guideline for R3 allows for the breaker status to be determined by analysis of suitably time synchronized FRs with the data provided in the manner detailed in R4. This should be identified in the Requirement itself. The guideline is a non-binding portion of a standard. (6) The guideline for R3 has a typo (it should reference R4 instead of R14). (7) Requirement R4 is not clear if determine means that the required BES Elements of TO and GO shall have waveforms for each phase current and the residual or neutral current. Regarding Requirement R4, Part 4.2, it is not clear if only high-side voltage winding voltages and currents need to be recorded. Clarification is needed if low-side voltage windings and transformer neutral need to be monitored also. (8) Part 4.1- More specificity is needed in the requirement. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads - “.... Voltages for each phase of either each line or bus.” which could be confusing. (9) Part 4.2 - Residual current and neutral current are two different quantities. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This wording should probably be more specific by stating if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the DMSDT). (10) Sub-Part 4.2.1 - Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific. (11) M4 (1): add “plus evidence the device was commissioned at the specific bus in question”.

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	(12) In Part 5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the requirement. We suggest R5.1 be reworded to say “A single record or multiple records that include at least one of the following:”. (13) Part 5.1 - the two bullet items in this requirement are confusing and should be reworded to clarify what is intended. (14) Part 5.1 Bullet 2- The wording should be changed as follows: “At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder.” Because the deployment of Fault Recorders are not required on every BES bus, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it is occurring more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it. (15) Part 5.2 assumes that SOE recording is driven by DFR analog sampling since it infers the achievement of a 1ms digital event resolution for a 960Hz (16x60Hz) analog sample rate. Stating analog and event resolution requirements (i.e. 16 samples per cycle and 1ms event resolution respectively) separately and explicitly is clearer and accommodates instances where SOER is separate from analog sampling. (16) Part 5.3.1. asks to have trigger settings for neutral (residual) overcurrent, which implies for R4 that it is necessary not only to determine but to monitor either each phase current or neutral current. (17) Regarding requirement R6, the standard should not create a new term like “Responsible Entity” but should only refer to specific NERC entities like TO, GO, RC, etc. (18) If the DMSDT decides to retain sub-Part 6.1.6, then it is recommended the phrase "all Elements associated with Interconnection Reliability Operating Limits" be replaced with "elements critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" similar to the language used in CIP-002-4. CIP-002-4 - Attachment 1 Critical Asset

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	Criteria reads:1.8. Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies. (19) There is an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The DMSDT has mapped this requirement to R14 of PRC-002-2. These two activities are not the same since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. R14 of PRC-002-2 requires entities to repair equipment that they know is in a failed state. (20) The Part 8.3 wording is too restrictive. Real and reactive power may not be able to be determined operationally if say a bus is split at the time of an event (or the split is caused by an event). Suggest the DMSDT correct this requirement by referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions Real and Reactive Power could be determined. The design should be assuming all normally-closed circuit breakers on a bus are closed. This avoids being out of compliance during a specific event, if open bus breakers preclude recording the MVA flows on all elements. (21) Requirement R10 should allow the legacy equipment to have multiple triggered records which make up the required length. It is stated that triggered records from existing equipment can be accepted in lieu of continuous recording if the triggered records meet the criteria in 10.1 and 10.2. If continuous recording is available and meet all criteria, are triggered DDR records required? (22) R13 - this requirement places the RC, RE and/or NERC in the middle of data sharing. There is no requirement in the standard to facilitate entities to partake in data sharing. Is this really the intent? What if adjacent entities need to exchange post-disturbance information? Does that really need to occur via the RC, RE or NERC if an entity cannot directly request necessary data? (23) Requirement R13, Part 13.3. asks for SOER data in Comma Separated Value (.CSV) format whereas the majority of Disturbance Monitoring Equipment (DME) do not save data in this

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	format. In addition, if breaker open/close position determination from FR data is acceptable, no .CSV file can be created by the recording tool itself. There is no need to require this data to be written in CSV format. Tab delimited text would work as well and would not limit the use of commas in descriptors or other entries. (24) The format described in Attachment 2 is limiting and incomplete (see comments on Attachment 2 below). (25) Similarly, R13 Part 13.4. asks for FR and DDR data in C37.111 , IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files whereas the majority of DME equipment does not save data in this format. Are manually converted records acceptable? This requires that Fault Recording and Disturbance Recording data will be provided in COMTRADE (C37.111) formatted files, but does not specify a revision level or year for the COMTRADE standard. The requirement should specify “C37.111-2013 or later” in order to require a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data. (26) In R14, reword to indicate that the second bullet is only applicable if the first bullet is not completed within 90 days. We suggest this wording for the second bullet - “If recording ability is not restored within 90 days, report the inability...” The Rationale for requirement R14 recognizes that the DME equipment cannot be always returned to service within 90 calendar days of the discovery of a failure. Requirement R14 itself, however, is not clear and should be rewritten to reflect that. (27) PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements.

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	(28) Regarding Attachment 2, the format in Attachment 2 is limited and incomplete. While the information required is obviously necessary, the format limits or omits information available from some SOERs. R13.3 states that the files must be comma-delimited, but Attachment 2 makes no statement about the length of any string or value. There is no provision for SOERs which may have detailed descriptors of the contacts being monitored but may be a single string. “Local Time Offset from UTC” should be expressed in hours before or after UTC rather than letter designations. There is no provision for acceptable terms for “State” except for “OPEN “and “CLOSE”. Other terms may be more appropriate for some devices monitored by an SOER, such as “ENABLED” or “DISABLED”, “ON” or “OFF”, etc. In short, Attachment 2 appears to be an attempt at defining a standard but does not adequately define a format. Development of such a standard may be better left to an IEEE Working Group or other entity.

Response: (1) The DMSDT intended that the bus location be the bus location identified in a system study, and further identifies it in Attachment 1 as “For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.” Steps 7 and 8 explicitly state “at least” 10% or 20% respectively.

(2) There is nothing that prevents a TO or RE from a too frequent assessment. The DMSDT does not believe that reassessment will result in a significantly different set of buses or elements for which data is required unless significant construction activity or reclassification of BES elements has occurred. If an entity is notified that they have a data obligation, the implementation plan for PRC-002 allows them three years to become compliant.

(3) (4) The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent.

(5) (6) The DMSDT has reviewed this language and removed it from the guidelines for R3 (now R2).

(7) The use of “determine” means that the stipulated data can be obtained by direct measurements or derived mathematically. Monitoring is not required on both sides of the transformers. Derived data is acceptable. The

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Requirement stipulates the determination of electrical quantities. We have added a clarification to the Rationale Box: "For transformers ((now)Part 3.2.1), the data may be from either the high side or the low side of the transformer." (8) The standard offers two option; either bus or line voltages. For each phase, you can use a bus or a line. The intent of the Requirement is to lay the foundation for capturing adequate data for event analysis. Bus voltages could be used in lieu of each of the Elements connected to that bus. (9) For the purposes of FR data, residual and neutral currents are the same. The DMSDT noted that the requirement is designed to have the entity provide data and the entity has flexibility as to how this is obtained or derived. Use of residual current or neutral current will provide the same results. They represent the zero sequence component of the fault current and are measured/determined by different techniques. (10) Monitoring is not required on both sides of the transformers. Derived data is acceptable. The Requirement stipulates the determination of electrical quantities. A clarification has been added to the Rationale Box: "For transformers (now Part 3.2.1), the data may be from either the high side or the low side of the transformer." (11) The DMSDT reviewed M4 (now M3) and found that the words "plus evidence the device was commissioned to capture data at the specific bus in question" did not need to be added because commissioning is not necessary for the acquisition of appropriate data.(12) A list with bulleted items is an "Or" list for the bulleted items. "Or" was added between the bullets of now Part 4.1 for clarification. (13) The DMSDT has revised the bullets for clarity: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 30 cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder. (14) The standard refers to data and not equipment. See the preceding response. (15) Part 5.2 (now Part 4.2) only applies to FR and there is no linkage to SER. The specifics of sequence of event and fault recording data are separate and succinct.	

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(16) The DMSDT agrees that the triggering specified in Part 5.3.1 (now Part 4.3.1) requires monitoring either all phase currents or neutral current. (17) Because of the different responsibilities of entities throughout the continent, the DMSDT decided that the use of Responsible Entity was most appropriate. Responsible Entity is not a new term and is used in other NERC standards. (18) The wording of Part 6.1.6 (now sub-Part 5.1.4) has been revised to “One or more BES Elements associated with each Interconnection Reliability Operating Limit (IROL).” (19) PRC-002 addresses the provision of data. It does not address equipment nor does it address maintenance of equipment. PRC-018-1, R6 addresses maintenance and that is not specifically required in PRC-002-2. The DMSDT is not prescribing a maintenance program in PRC-002-2 and is only requiring that a failure of data recording is corrected according to R14 (now R12). The Notes Section on p. 13 of the Mapping Document explains the rationale behind mapping PRC-018-1 Requirement R6 to PRC-002-2 Requirement R14 (now R12). From the Mapping Document: “PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R14 (now R12) deals with the long term availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability.” The Mapping Document was revised to reflect the R14 (now R12) wording. (20) The DMSDT has added verbiage to the Guidelines section of the standard to indicate this: “The data requirements for PRC-002-2 are based on a system configuration assuming all normally closed circuit breakers on a bus are closed.” (21) As stated in Requirement R10 (now R8), if there isn’t continuous data recording on already installed equipment, Parts 10.1 (now Part 9.1) and 10.2 (now Part 9.2) must be met. If continuous recording is available for Elements, then the triggered recording is not required for those Elements. (22) Entities can share data with whomever they deem necessary as it is not precluded in the standard. This Requirement ensures that the RC, or NERC get the data because the intent of PRC-002-2 is to ensure that there is data available to analyze	

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wide-area disturbances. This Requirement does not state that data has to go through the RC, RE, or NERC. The dictates for sharing data are outside the scope of this standard. (23) The DMSDT discussed and decided on the .CSV format as being universally acceptable to industry. The .CSV format was selected to ensure uniformity in data collected. (24)(25) The DMSDT has added language to clarify Part 13.4 (now 12.4) to indicate the version of C37.111 should be C37.111-2013 or later. (26) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be developed. R14 (now R12) and its Rationale Box were revised to clarify. (27) The DMSDT is aware of NPCC's PRC-002-NPCC-01, and that its DMSDT has been reconvened to review the Regional Standard with respect to PRC-002-2 after it is approved. There won't be a variance for the NPCC Standard, because after review if requirements in PRC-002-NPCC-01 were more stringent than PRC-002-2 they would be kept. (28) The intent of Attachment 2 was to only show what would be minimally required. There is nothing to prevent the inclusion of additional data. It is not intended to have any string or value length on Attachment 2. The "Local Time Offset from UTC" column heading has been revised to reflect hours before or after UTC. The footnote for the "State" column has been revised to indicate that "OPEN" or "CLOSE" must be used for circuit breakers to be consistent with Requirement R3 (now R2), and a note added that other status monitoring indication wording can be used for devices other than circuit breakers.	
Dynegy	(1) Regional Standard PRC-002-NPCC-01 technical specifications for DDR conflict with PRC-002-2 technical specifications. The NPCC Regional Standard R9 specifies a DDR recording rate of 6 times per second while PRC-002-2 specifies 30 times per second. Conflicts with the Regional Standard should be removed so entities are not penalized for Regional Standard compliance.
Response: (1) As explained in the Guidelines for Requirement R11 (now R9), the 30 times per second output recording rate is necessary to capture certain dynamic events. If the NERC standard is met, NPCC requirements will be exceeded.	

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SPP Standards Review Group	(1) Requirement R2 calls for Transmission Owners to notify other owners (who would also be Transmission Owners) of other facilities within the locations identified in Requirement R1. There could conceivably be situations where multiple owners would be involved and possibly none of the owners was able to identify 11 locations as specified in R1. In this situation, those particular facilities would not be required to have SOER or FR equipment even though the impact of those facilities could be significant on the BES. While this situation may be very unlikely to occur, it is still a possibility. (2) In Requirement R2 and its associated Rationale Box as well as throughout the posted documents, check for hyphenation of terms such as 90-calendar days, 60-calendar days, 30-calendars days, etc. (3) In the Rationale Box for R8 modify the single-line, paragraph to read 'Because all of the buses within a location are typically at the same frequency, one frequency measurement is adequate.' (4) In the 1st paragraph under the Guideline for Requirement R1 section in the Guidelines and Technical Basis, modify the next to last line to read '...voltage and current for individual circuits allow precise reconstruction of events of both...'. (5) Check the usage of wide-area and make sure it is properly hyphenated throughout the standard and the posted documents. Something appears to be missing in the 2nd sentence in the last paragraph under the Guideline for Requirement R1 section in the Guidelines and Technical Basis. 'Five years is long enough to avoid unnecessary, but long enough to adapt...'. To avoid unnecessary what? In the 1st line of the 2nd paragraph under the Guideline for Requirement R5 section in the Guidelines and Technical Basis, change 'Pre and post...' to 'Pre- and post-...'. In the 2nd line of the same paragraph, change 'SOE' to 'SOER'. In the 6th and 8th lines of the same paragraph, hyphenate '50-cycle post trigger'. In the 2nd line of the 4th paragraph under the Guideline for Requirement R5 section in the Guidelines and Technical Basis, replace 'Oscilloscope' with 'oscilloscope'. In the 7th line of the 4th paragraph under Guideline for Requirement R6 section in the Guidelines and Technical Basis,

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	modify the line to read '...interfaces are defined by the Regional Entity. In the ERCOT and Quebec Interconnections, the...'.In the Guidelines for Requirement 7 and Requirement 12 in the Guidelines and Technical Basis, the reader is referred to the Rationale Boxes in the standard for the information on those requirements. Once the standard is approved, the Rationale Boxes will disappear. We suggest going ahead and inserting the material from those boxes here even if it is redundant. In the 1st line of the 1st paragraph under Guidelines for Requirement R8, revise the line to read 'Dynamic Disturbance Recording measures transient response to system disturbances after a fault is...'.In the 3rd line of the 1st paragraph under Guidelines for Requirement R10, revise the line to read '...analysis. Pre- and post-contingency data help identify the causes and effects of each event...'.Modify the 1st line of the 1st paragraph under Guidelines for Requirement R11 to read 'Dynamic Disturbance Recording contains the dynamic response of a power system to a...' or 'Dynamic Disturbance Recording contains the dynamic response of power systems to a...'. In the 3rd line of the same paragraph hyphenate 'short-term' and 'long-term'. In the 4th line of the same paragraph delete the 'the' such that the line reads '...interest is changing over time, Dynamic Disturbance Recording is normally stored in the...'.We suggest the following to replace the 1st sentence in the 1st paragraph in the Guideline for Requirement R13: 'This requirement directs the applicable entities, that upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SOER and FR data for locations determined in Requirement R1 and DDR data for Elements determined in Requirement R6.Replace 'was' with 'were' in the 4th line of the 6th paragraph in the Guideline for Requirement R13 section of the Guidelines and Technical Basis. We suggest the DMSDT number the pages in Attachment 1 and the Guidelines and Technical Basis document.

Response: (1) Attachment 1 has provisions for when an entity cannot identify 11 locations. Step 3 states: "If the list has 11 or fewer buses, proceed to Step 7."

(2) The DMSDT made the necessary wording and grammatical revisions to the standard.

(3) The DMSDT has made the suggested revision.

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(4) The DMSDT has made the revision. **(5) The DMSDT made the necessary wording and grammatical revisions to the standard. Wide-area has been hyphenated in the standard. The Rationale Boxes stay with the standard after it is approved. They get moved to the end of the standard.**	
Luminant Generation Company LLC	(1) Requirement R4 as written could require both the Transmission Owner and the Generator Owner to monitor the requested electrical quantities for all lines and elements at the bus or switchyard where the generator is interconnected. R4 needs to be re-written to clarify that the GO is only responsible for monitoring for faults on the equipment it owns and the same for the TO. (2) For Requirement R13, subsections 13.3, 13.4 and 13.5 should be deleted from the standard entirely. These items are completely administrative in nature and are not results based. An entity could make a typo mistake in formatting or when naming a file and be non-compliant with the requirement. Also, the sub-requirements reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. (3) Finally, the standard is written in a confusing format where twelve of the 14 requirements in the standard reference other requirements, which in many cases reference another requirement (or two). As a GO, I need to know, in a clear concise manner, what electrical quantities or status I need to monitor where, and what attributes are needed for the disturbance monitoring equipment
Response: (1) The wording of Requirement R4 (now R3) has been revised. "Each Transmission Owner and Generator Owner shall have the following FR data to determine the following electrical quantities for each of the BES Elements they own connected to the BES buses identified in Requirement R1:"	

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(2) The need for the items in Parts 13.3 (now Part 12.3), 13.4 (now Part 12.4), and 13.5 (now Part 12.5) were made necessary due to problems with formatting of the submitted data after the 2003 Blackout. Data submitted was in different formats, making a difficult task that much harder. Because of the necessity to have data in the right formats, Parts 13.4 (now 12.4) and 13.5 (now 12.5) are needed. **(3) Making references between requirements in the standard was necessary to avoid repetition and wording. Requirements referencing other requirements simplify the measures. Requirements R1 and R2 have been combined (into what is now R1) which reduced the number of requirements referencing other requirements.**	
ReliabilityFirst	(1) Requirement R4, Part 4.2.1 - With the forthcoming approval of the NERC BES Definition including “Transformers with the primary terminal and at least one secondary terminal operated at 100 kV...”, ReliabilityFirst does not believe the informative language in Requirement R4, Part 4.2.1 is needed and recommends removing the following language from Requirement R4, Part 4.2.1: “that have a low-side operating voltage of 100kV or above” since it serves no purpose. (2) Requirement R14 - ReliabilityFirst does not believe there is any value for an Entity to report their inability to record data (due to a failure of a FR, SOER or DDR) to the Regional Entity. ReliabilityFirst believes the record keeping will be burdensome with little or no benefit. ReliabilityFirst would rather like to see the Entities get the corrective actions plans in place and the equipment fixed, thus the Regions really have no need for this type of report. Compliance can be monitored through a data submittal on an annual basis rather than an ongoing reporting requirement. Also, even though a bulleted list in a Reliability Standard indicates an “or” statement, it is still unclear that these are considered two options. ReliabilityFirst recommends adding the word “either” after the word “shall” in the parent Requirement R14 and including the word “or” after the word “ability” in the first bullet. ReliabilityFirst also recommends the following to remove the Regional Entity from the second bullet and adding a time frame for when the CAP needs to be completed (it should not be open ended): “Develop and implement a Corrective Action Plan (CAP) to restore the recording ability within xx days.”

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	Also, the CAP should not have an open-ended time frame for completion, such as years into the future. There needs to be some time limit for correction.
Response: (1) The DMSDT has retained the language to emphasize different transmission levels. This requirement excludes GSU transformers. **(2) Oversight is needed for the availability of Disturbance monitoring recording capability, and in the revised R14 (now R12) wording the DMSDT stipulates the submission of a Corrective Action Plan to the Regional Entity. The DMSDT has also added language to R14 (now R12) that requires the entity to include a timeline for restoration of data recording ability within the CAP.**	
ISO New England Inc.	(1) Requirement R5.1 currently reads:5.1. A single record or multiple records that include: o A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. o At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault.Comment R5.1 - the two bullet items in this requirement are confusing/conflicting and should be reworded to clarify what is intended. I.E. is it 50 cycles per bullet 1 or three cycles per bullet 2? This is probably for single and multiple records but the language should identify the difference as shown below. o A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. (Single Record Only) o At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault. (Multiple Records Only) (2) Comment on R13, this requirement could place the Reliability Coordinator/Planning Coordinator in the middle of data sharing. This requirement should encourage direct sharing of data. (3) Also, R13.3 and Attachment 2 attempts to define yet another format for SOE data; There are well established formats for this type of data, such as COMTRADE, that include many other aspects of data such as file and signal naming conventions.

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Response: (1) "Or" was added between the bullets of Part 5.1 (now 4.1) for clarification. Both bullets of 5.1 (now 4.1) are needed to address the Fault Recording capability that is available to industry. The DMSDT has changed 50 cycles to 30 cycles in the first bullet. The bullets, as stated in the standard, apply to single or multiple records. (2) Entities can share data with whomever they deem necessary as it is not precluded in the standard. This requirement ensures that the RC, Regional Entity, and NERC get the data because the intent of PRC-002-2 is to ensure that there is data available to analyze wide-area disturbances. This requirement does not state that data has to go through the RC, RE, or NERC. The dictates for sharing data are outside the scope of this standard. (3) The DMSDT discussed and decided on the .CSV format as being universally acceptable to industry. The .CSV format was selected to ensure uniformity in data collected. COMTRADE is for transient data reporting and binary data associated with it.	
Seattle City Light	(1) Seattle City Light appreciates the effort of the DMSDT in developing this proposed Standand, and understand the concept to focus requirement on data requirements rather than equipment requirements. That said, Seattle does not support this draft or approach. The draft is far too complex and technical to be an effective Federal regulation, in part because it requires a slow and cubmersome process to update each time a technical specification goes out of date. Seattle recommends that the Standard be revised to provide general requirements that are consistent over time, with details referenced in a separate document similar to the data collection and data preparation manuals associated with data-collection regulations in other areas (such as for regional model development). Additionally, Seattle cannot support such a detailed and complex Standard until additional guidance is available about the compliance implications, such as an RSAW or guidance document.
Response: (1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report: "Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.	

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A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices."

Project 2007-11 – Disturbance Monitoring was initiated to address the existing PRC-002-1 "fill in the blank" standard. FERC did not approve or remand PRC-002-1 in its Order No. 693 (March 16, 2007) because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the "fill in the blank" aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). The consolidation of these two Standards will result in a Standard that fully addresses what is necessary to capture power system disturbance data.

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data.

The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.

Technical specifications will be superseded over time, but those contained in the standard will not require immediate attention that at present is not afforded by the revision process. Specificity in the requirements has been made intentionally general where possible to provide consistency. The Rationale Boxes (which stay with the standard) and Guidelines provide specifics, and background information. The standard was written minimizing the technical details. The RSAW for PRC-002-2 is to be posted at a later date.

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Western Area Power Administration	(1) Section 5.3 - Disagree with the trigger requirements as written. There are many factors that contribute to effective triggering such as: o Triggering for local vs. remote faults o Avoiding over-triggering that could result in "information overload" and the filling up of data storage o Capturing relevant and complete fault representationThe requirements stated are inadequate. It is felt that trigger settings are best left to the professional judgement of the relay engineer. While triggering on Neutral (residual) overcurrent is often standard, care must be taken regarding the sensitivity level. Similarly, triggering issues related to sensitivity and pickup time are associated with phase undervoltage triggering. Other triggering methods (such as based on protection element pickup) may be preferred instead of undervoltage methods. (2) Section R13 - the requirements of R13.4 and R13.5, while achievable, are somewhat archaic. More flexibility should be allowed for frequently used, industry standardized fault recording formats such as SEL event records. Also, the naming convention put forth in C37.232 is not the easiest to follow.
Response: (1) Triggering setting values are not specified in Part 5.3 (now Part 4.3), just the quantities to be used as triggers. Additional triggers may be set based on professional judgment. **(2) The formats listed were established from knowing what is available to and being used by industry**.	
Liberty Electric Power LLC	See NAGF SRT comments.
Response: Please see the DMSDT response to the NAGF SRT comments.	
Colorado Springs Utilities	(1) Thank you standard DMSDT for all of your efforts. We believe that all of the disturbance monitoring equipment referenced in this standard can be very helpful to an organization. We do not believe that it has a reliability impact that merits the cost in time and money to install, maintain, and report on all these devices as specified in the standard. As shown by the VRFs this does not highly impact reliability and although disturbance monitoring is something that

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	could be useful, at times, should not be part of a mandatory standard. If a standard is to be implemented, we view the approach as written, to be too broad and cumbersome. We would recommend that a technical criteria based on system configuration be established to identify critical points for disturbance monitoring (DM) and that DM be implemented at those locations. We believe a more focused and technically based approach to placement of DM equipment would yield higher benefits while eliminating unnecessary and undesirable impacts.

Response: (1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:

"Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.
A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices."
Project 2007-11 – Disturbance Monitoring was initiated to address the existing PRC-002-1 "fill in the blank" standard. FERC did not approve or remand PRC-002-1 in its Order No. 693 (March 16, 2007) because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the "fill in the blank" aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). The consolidation of these two Standards will result in a Standard that fully addresses what is necessary to capture power system disturbance data.

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data.

Organization	Question 7 Comment
The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.	
N/A	The DMSDT and NERC staff are to be commended for the work done, this being such a complex standard. They have taken the right approach by addressesing “what” (data) is to be captured, not “how” and by not considering Disturbance Monitoring equipment. However,additional work is needed to make this standard acceptable. (1) The way R2 is worded presently, it sounds like a TO is required to notify itself if it owns BES Elements at the bus locations. The only action in R1 should be to identify busses for DME, expanded to indicate that after the busses are identified the TO needs to have DME on the Elements that are owned by the same TO and notify such identification for the Elements owned by others, if any. (2) R4.1- As written, this requirement could be confusing. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads - “.... Voltages for each phase of either each line or bus.” which could be confusing. (3) R4.2 - Residual current and neutral current are two different things. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This requirement should specify that if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the DT). (4) R4.2.1 - Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific. (5) R5.1 Bullet 2- The wording should be changed as follows: “At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder.” Since the deployment of Fault Recorders is not required on every BES bus location, unless the fault is being cleared on an Element directly connected to the bus, the fault

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	recorder may not always accurately capture the fault information if it occurs more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it. (6) There seems to be an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The DT has mapped this requirement to R14 of PRC-002-2. These two activities are not the same at all since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. In fact preventative maintenance should reduce the failures. R14 of PRC-002-2 requires entities to repair equipment that they know are in a failed state. (7) Real and reactive power may not be able to be determined operationally if for example, a bus is split at the time of an event (or the split is caused by an event). Suggest the DT correct this requirement by perhaps referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions, Real and Reactive Power could be determined. (8) R3, R4, R12, R13, R14 all reference “the bus locations as per Requirement R2” however this requirement is a notification requirement only for Elements not owned by the TO that need DME. These requirements need to refer to both R1 and R2. (9) R3, R4, R12, R13, R14: List of locations that need Sequence of Events Recorders and Fault Recorders is identified in R1 and communicated in R2. Suggest replacing reference to R2 with R1 (10) R8,9,10,11 and R13, R14: Suggest changing reference to R7 with R6 (see the comment for R3 and R4 above).

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Response: (1) The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent. **(2) The requirement has been revised to specify the determination of each phase of each specified BES bus. The intent of the Requirement is to lay the foundation for capturing adequate data for event analysis** **(3) For the purposes of FR data, residual and neutral currents are the same. The DMSDT noted that the requirement is designed to have the entity provide data and the entity has flexibility as to how this is obtained or derived. Use of residual current or neutral current will provide the same results. They represent the zero sequence component of the fault current and are measured/determined by different techniques.** **(4) Monitoring is not required on both sides of the transformers. Derived data is acceptable. The Requirement stipulates the determination of electrical quantities. A clarification has been added to the Rationale Box: "For transformers (now Part 3.2.1), the data may be from either the high side or the low side of the transformer."** **(5) The standard refers to data and not equipment. The DMSDT has revised the bullets for clarity:** • **A pre-trigger record length of at least two cycles and a post-trigger record length of at least 30 cycles for the same trigger point, or** • **At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.** **(6) PRC-002 addresses the provision of data. It does not address equipment nor does it address maintenance of equipment. PRC-018-1, R6 addresses maintenance and that is not specifically required in PRC-002-2. The DMSDT is not prescribing a maintenance program in PRC-002-2 and is only requiring that a failure of data recording is corrected according to R14 (now R12). The Notes Section on p. 13 of the Mapping Document explains the rationale behind mapping PRC-018-1 Requirement R6 to PRC-002-2 Requirement R14 (now R12). From the Mapping Document: "PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R14 (now R12) deals with the long term**	

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availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability." **(7) Regarding Requirements R8 (now R6), and R9 (now R7), the DMSDT has added verbiage to the Guidelines section of the standard to indicate this: "The data requirements for PRC-002-2 are based on a system configuration assuming all normally-closed circuit breakers on a bus are closed."** **(8, 9) The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent.** **(10) Requirement R7 (now R5) has been revised for clarification and appropriateness to use as the reference**.	
MRO NSRF	(1) The NSRF believes that this Standard should apply only to those devices already installed by the Generator Owners and Transmission Owners on BES Elements. The DMSDT has already made it clear that there is an abundance of these devices on the BES. Therefore, a footnote should be added that the Registered Entities are not required to spend the ratepayers' money to buy new equipment to satisfy the requirements of this Standard. The NSRF proposes it should read "Each Transmission Owner and Generator Owner is not required to have Dynamic Disturbance Recording, Fault Recording, or Sequence of Events Recording devices which capture the essential data of PRC-002-2, installed or activated on its BES Elements." This would be incredibly comparable to footnote 1 of the industry-approved NERC Standard PRC-024-1. That footnote states "Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit."

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Response: (1) It is intended that this standard ensure the capture of adequate data to analyze major system disturbances, and the wording reflects that intention. The standard addresses not "how" the data is captured, but "what" data is captured.	
Arizona Public Service Company	The proposed standard still needs work before it is acceptable. The following items need to be addressed: (1) The standard requires all owners of identified BES elements to implement the various types of recording. However, for jointly owned facilities, this puts co-owners in a position whereby they can be held in violation of the standard if the operating/maintenance entity of a co-owned facility does not implement and maintain compliance with the standard. For jointly owned facilities, the standard should specifically address which of the co-owners (preferably the co-owner that operates or maintains the facility) is responsible for compliance with the standard. (2) Requirement 14 needs to be re-written. As it is now written, R14 requires that a TO or GO formally report to the Regional Entity an outage of any of the recording capabilities covered by the standard along with a Corrective Action Plan. However, in the "Rationale for R14" discussion that is included it is clear that the intent or this requirement is to require the TO/GO to report the problem only if they cannot restore the lost recording capability within 90 days. The requirement needs to be re-written to state the actual intent because as it is now written, one must contact the Regional entity every time the recording capability goes out, no matter how long it went out for. (3) Requirements R10 through R13 all seem to be required specifications and shouldn't have their own requirements but could rather be combined into an Appendix to the standard. (4) The standard should allow for monitoring/recording up to the capability of the equipment presently installed (this is not referring to the capability of the presently installed recording capability but rather the presently installed BES equipment capability). A utility shouldn't have to install major

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	equipment (CCVTs, breakers, etc) just to meet the standard if their presently installed equipment doesn't allow adequate monitoring. (5) In Requirement R3 it is not clear if a GO will be required to monitor a low side generator breaker. The standard refers to breaker connected to the identified bus location. If this refers to each breaker that is directly connected to the bus location, the requirement should use the term "directly". Without qualifying as such, the question remains as to whether the low side breaker qualified as being connected to the bus since it is connected to the bus through the GSU transformer.
Response: (1) The registered owner that is responsible for compliance with NERC standards would be the one responsible for this standard as well. **(2) The wording of Requirement R14 (now R12) and its Rationale Box has been revised for clarification. See the Rationale Box for an explanation of the intent of this requirement**. **(3) The DMSDT considered combining Requirements R10 through R13, but decided that it was simpler and created a less cumbersome standard to leave them as separate requirements.** **(4) The requirements allow for flexibility in how the data is captured. Requirement R4 (now R3) requires entities to be able to determine electrical quantities, not actually have to measure them.** **(5) Requirement R3 (now R2) only relates to BES Elements determined by the Transmission Owner in Requirement R1. These Elements are connected to the TO's BES buses and do not include generator transformer low side breakers.**	
Tacoma Power	(1) There is general concern about the cost of implementation, especially cost sharing for installation of Dynamic Disturbance Recording (DDR). For example, the Responsible Entity seems to have latitude on selecting BES Elements, beyond the DDR locations identified in Requirement R6, Parts 6.1.3 through 6.1.7, and therefore which Transmission Owners and Generator Owners must install DDR to meet Requirement R6, Part 6.1.1. (2) If two Transmission Owners share equipment at a BES bus location, which Transmission Owner is responsible under R1 and R2 for identification and notification?

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	(3) Under Requirement R5, Part 5.1, do the bulleted items constitute an 'and' or 'or' condition? For example, if a post-trigger record length of 50 cycles is available, but a fault lasts 51 cycles such that the final cycle of the fault is not captured, would this be compliant with the intent of Requirement R5, Part 5.1? If not, then it seems that either (1) both bulleted items would be required or (2) just the second bulleted item would be required. Consider changing "a single record or multiple records that include:" to "a single record or multiple records that include at least one of the following:" (4) Under Requirement R5, Part 5.3, what latitude are Transmission Owners and Generator Owners afforded in establishing thresholds for neutral (residual) overcurrent and phase undervoltage trigger settings? (5) Under Requirement R6, Part 6.1.7 attempts to define every area that uses UVLS as a "Major Voltage Sensitive Area." UVLS programs are also used to address localized voltage issues. As currently written, a DDR would be required for every entity that uses any undervoltage relays, no matter how localized. We suggest removing section 6.1.7 as the other criteria in requirement 6 will provide widespread installation of DDRs. (6) Under Requirement R8, Part 8.2, consider changing "...same voltage corresponding to..." to "...same voltage level corresponding to..." (7) Under Requirement R9, Part 9.4, consider changing "...of at least one of..." to "...of any of..." (8) Under Measurement M12, consider explicitly adding "station drawings," or similar verbiage, as evidence. Device specifications and configuration or actual data recordings may be insufficient to demonstrate time synchronization; it may be necessary to demonstrate that cabling is connected. (9) If failure of DDR is discovered, recorded data may not be retrievable for the period of 10 calendar days preceding a request. If a disturbance occurs before recording ability is restored, but an entity is compliant with Requirement R14, is it the intent of the standard that an entity could be found non-compliant with Requirement R13 for the failed DDR? (10) Under Measurement M13, change "...evidence (electronic or hard copy) data..." to "...evidence (electronic or hard copy) that data..."

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	(11) Under Requirement R14, does loss of time synchronization qualify as a "failure"? Generally, it seems that this type of issue would be corrected quickly (within 90 calendar days of discovery) and therefore not require reporting. (12) Under Requirement R14, if a Transmission Owner or Generator Owner restores the recording ability within 90 calendar days of the discovery of a failure, does the failure need to be reported to the Regional Entity to be compliant with Requirement R14? In other words, do the bulleted items under Requirement R14 constitute an 'and' or 'or' condition? (13) In Attachment 1, Step 1, would bus Elements on the high-side of transformation at the same physical location be considered a single bus location and be distinct from the bus Elements on the low-side of the transformation, even if both sets of bus Elements share a common ground grid? In other words, is it possible to have two bus locations at the same physical location, even if they share a common ground grid, provided that there is transformation connecting the two bus locations? Consider a 230kV to 115kV substation. (14) In Attachment 1, Step 1, what is meant by the verbiage "...or from other DME devices"? Additionally, the acronym 'DME' does not appear to be defined in the standard itself (only in the Rationale for R14).

Response: (1) DDR data requirements are to be established by the RC in the WECC. The standard provides criteria for the location for DDR data that the RC is required to follow which minimizes the risk of arbitrary selection of DDR data locations. The standard is about "what" data is captured, not "how" it is captured.

(2) The registered owner that is responsible for compliance with NERC standards would be the one responsible for this standard as well.

(3) A list with bulleted items is an "Or" list for the bulleted items. "Or" was added between the bullets of Part 5.1 (now Part 4.1) for clarification. Both bullets of 5.1 (now 4.1) are needed to address the Fault Recording that is available to industry. The DMSDT revised 50 cycles to 30 cycles.

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(4) The DMSDT notes that the Requirement R5 Part 5.3 (now R4 Part 4.3) does not specify settings. Dictating the actual trigger settings is outside the scope of this standard. (5) Part 6.1.7 (now Part 5.1.5) stipulates "Any one Element within a major voltage sensitive area…" The Guideline for Requirement R6 (now R5) says "Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are areas of significant Load." The Standard DMSDT has revised Requirement R6 (now R5) to clarify the dynamic disturbance recording data for UVLS. (6) Based on other comments received, the DMSDT revised Part 8.2 (now 6.2) to "at the same voltage in Requirement R6, Part 6.1…" (7) The DMSDT retained the original language (8) The wording of Measure M12 (now M10) has been revised to include station drawings. (9) An entity would not be non-compliant for not being able to capture data for the situation presented. (10) The Standard DMSDT has revised the wording in Measure M13 (now M11). (11) Loss of time synchronization is considered a failure andR14 (now R12) would apply. (12) The wording of Requirement R14 (now R12) and its Rationale Box have been revised for clarification. Refer to the Rationale Box for an explanation of the intent of this requirement. (13) The DMSDT intended that the bus location be the bus location identified in a system study, and has revised Attachment 1 Step 1 to read "For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid." The example presented in the comment would be counted as two bus locations. (14) "…or from other DME devices" appears in Step 8, and the intent is that the disturbance monitoring recording devices should be electrically distant to maximize the recording coverage of the BES.	
Ameren	We request the DMSDT to make the following changes:

Organization	Question 7 Comment
	(1) In R1, add 'After identifying BES bus locations, each TO shall identify the BES Elements directly connected to that bus location at its voltage level.' We request allocating another month to do so. We believe that this will provide a consistent reference for R2 which refers to BES Elements as if they've been established in R1. (2) In R3, insert 'Transmission Owner' before 'bus locations' to make it consistent with the page 32 Guideline for R3 explanation that the GO does not need SOER at its GO bus locations. Also insert 'BES' between 'each' and 'circuit breaker' because not all breakers are BES Elements. It then states 'Each Transmission Owner and Generator Owner shall have Sequence of Events Recording (SOER) for circuit breaker position (open/close) for each BES circuit breaker they own connected to the Transmission Owner bus locations as per Requirement R2.' (3) Include the BES bus location along with the BES Element in R6 so that it is clear that DDR is only required at one terminal of a two-terminal Element. (4) Reword R8 and R9 to 'Each Transmission (Generation) Owner shall have Dynamic Disturbance Recording (DDR), for each location and Element as dictated by the Responsible Entity per Requirement R7, to determine...' (5) Reword R11 to be similar using 'that is responsible for' to R10 to 'Each Transmission Owner and Generator Owner that is responsible for Dynamic Disturbance Recording (DDR) as per Requirement R7 shall conform ...' (6) Reword R12 to 'Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 shall time synchronize data to within ...' (7) If at all possible we would like another opportunity to provide comments on CEAP for PRC-002-2 in the next draft. Several aspects of this draft made in unclear as to what is required, and therefore difficult to assess cost impact.

Organization	Question 7 Comment
Response: (1) The DMSDT has combined R1 and R2 (into what is now R1) to help clarify the responsibilities. The DMSDT has discussed and decided that the 90 calendar days are sufficient for notifications. **(2) The DMSDT has revised the wording in Requirement R3 (now R2) to read "…for each circuit breaker they own connected directly to the BES buses identified in Requirement R1, ..."), and combined Requirements R1 and R2 (into what is now R1) to clarify the responsibilities.** **(3) DDR refers to data capture for BES Elements, and not "how" or from where the data is captured. Only Requirement R6 (now R5) only specifies "Each terminal of a high-voltage direct current (HVDC) circuit…". Wording was added to the Rationale Box to make this clarification.** **(4) The wording of Requirements R8 (now R6) and R9 (now R7) have been revised in response to comments received to clarify that the intent is to capture the data for the BES Elements owned.** **(5) The wording of Requirement R11 (now R9) has been revised to clarify responsibility.** **(6) The wording of Requirement R12 (now R10) has been revised to clarify responsibility.** **(7) The second posting CEAP comments closed Feb. 7, 2014. Unless substantive changes are made to the standard there will not be another CEAP posting. A report was going to be generated by the CEAP review team.**	
SERC Protection and Controls Subcommittee	We request the DMSDT to make the following changes: (1) The Requirements of R3, R4, R5 and R12 for SER and FR data should be included as part of a single attachment/ table and R3 should simply reference the table. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation multiple Requirements. (2) Similar to 1) above, Requirements R8, R9, R10, R11, and R12 for DDR data should be included as part of a single attachment/ table or possibly separate attachments/tables for TOs and GOs and referenced in a single Requirement. As structured presently, if an owner fails to include or

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	provide data for a single required element, they would be in violation of multiple Requirements. (3) Provide at least one example in the Guidance Section, or develop a reference document similar to the BES Definition effort. A system one line similar to BES Definition Reference Figure S1-1 augmented with circuit breakers in various configurations (e.g. straight bus, ring bus, breaker-and-a-half). The DMSDT could go through the various Requirements to demonstrate the DMSDT intentions. Although the present guidance and rationale are helpful, we believe there are still many unclear aspects to these Requirements. (4) Add 'by voltage level' in Requirement R1 so that it reads 'Each Transmission Owner shall identify BES bus locations by voltage level for Sequence of Events Recording (SOER) and Fault Recording (FR).' This is consistent with Attachment 1, Step 1 and clarifies that the FR and SOER are only required at that voltage level. (5) In Requirements R1.2 and R 6.2, what prevents a TO or RE from assessing the locations and elements on too frequent of a time basis? As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability in where monitoring is really needed. Frequent assessments could jockey locations above and below the minimum criteria line and create confusion. (6) In Requirement R2, it infers that the TO as part of Requirement R1 develop a list of Elements;, however, Requirement R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest Requirement R2 be reworded to say "Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify...". If it was the intent that the GOs (and other affected TOs)

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	to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. Time has to be allotted to allow identifying the Elements at the BES bus locations.Element ownership sometimes changes between the two terminals of an Element, so this needs to be addressed. GO and TO are each concerned with the unwarranted cost burden this standard proposes, and there will be disputes as to cost responsibility. (7) Use a consistent footer (pages 18 through 40 say Draft 1), and number the pages throughout (they stop at page 25 of 40). (8) Clarify the intent of Requirement R3 which we believe is unclear. The DMSDT may intend that a breaker auxiliary contact be connected to the SOER to provide circuit breaker position. Page 32 Guideline for Requirement R3 last sentence implies that breaker status can be determined from the FR. However page 33 last sentence under Recording of Electrical Quantities suggest that these only augment the SOER. (9) Add 'including generator interconnection facilities' after Transmission lines in Requirement R4 to be consistent with page 32 Guideline and Project 2010-07. (10)In Requirement R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the Requirement. We suggest Requirement R5.1 be reworded to say "A single record or multiple records that include at least one of the following:" (11)Reword Requirement R13 to 'Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 shall provide data for those BES Elements to the Regional Entity upon request.' The regions already have a process for collecting these types

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	of data and can act as a clearinghouse if indeed the Reliability Coordinator and/or NERC need the exact same data. The reality is that all these entities will collaborate in the disturbance analysis if an event of this magnitude ever does occur. It is unreasonable to require the TO and GO to respond to duplicative data requests in such a short time. (12) Reword Requirement R14 to 'Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 upon the discovery of a failure shall: (a) Restore the recording ability within 120 calendar days; or (b) If recording ability is not restored within 120 calendar days, demonstrate efforts to correct the unresolved failure.' Please increase the allowed repair time by 30 days because the access of repair personnel to such equipment is often restricted during certain periods of the year. In addition; revise the second part to be consistent with the handling of Unresolved Maintenance Issues in PRC-005-2 R5. This change triggers an M14 part (3) change to "(3) if not repaired within 120 calendar days of discovery, evidence that it has undertaken efforts to correct the unresolved failure Issues in accordance with Requirement R14. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.' We believe that the proposed reporting requirement is much too burdensome for this equipment.

Response: (1)(2) Each of the Requirements mentioned has its own specific reliability objective. Combining these requirements would have requirements with multiple reliability objectives which is contrary to the purpose of a requirement, and could present compliance difficulties. The Requirements for SER and FR are sufficiently unique where there can be no violation of multiple requirements. The proposed definitions for SOER, FR, and DDR have been removed from the standard.

(3) The DMSDT has revised the Rationale Boxes and Guidelines (included diagrams where it was felt to be necessary) to clarify what the intended system configurations are.

Organization	Question 7 Comment
	(4) The DMSDT feels that adding the additional language to Requirement R1 (R1 is now the combined R1 and R2) does not add any clarification to the requirement because it is stipulated in Attachment 1. (5) There is nothing that prevents a TO or RE from a too frequent assessment. The DMSDT does not believe that reassessment will result in a significantly different set of buses or elements for which data is required unless significant construction activity or reclassification of BES Elements has occurred. If an entity is notified that they have a data obligation, the Implementation Plan for PRC-002 allows them three years to become compliant. (6) The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent. The Element owner is responsible for the data capture. The CEAP postings gave the opportunity to provide cost input. (7) The page numbering and footer has been made consistent throughout the standard. (8) The Requirement R3 (now R2) Rationale Box was revised to clarify that the intent is to have the SER data breaker status, not how. (9) The wording in Requirement R4 (now R3) and the associated Guideline have been made consistent. (10) The bullets reflect the capabilities of the means of recording that are available. A list with bulleted items is an "Or" list for the bulleted items. "Or" was added between the bullets of Requirement R5 (now R4) for clarification. (11) Because the intent of the standard is to capture BES disturbances, the R13 (now R11) entities will be involved with the necessary data exchange. The standard does not prohibit individual entities from sharing data amongst themselves. The intent of Requirement R13 (now R11) is not to encourage duplicative requests for data. If that should occur it should not place a burden on an entity. An entity would already have the data available.

Organization	Question 7 Comment
(12) **The intent of Requirement R14 (now R12) is to have an entity restore recording capability within 90 days, but if that 90 day window couldn't be met then the Regional Entity would have to develop a Corrective Action Plan. The 90 day window is realistic and practical, and compliance should not be burdensome to an entity. The wording of Requirement R14 (now R12) has been revised for clarification.**	
Edison Mission Marketing & Trading Inc.	(1) While we believe that our Wind sites have a low risk of being one of the selected entities required to install & maintain disturbance monitoring equipment, the standard provides no compensation for the purchase, installation, and maintenance of this equipment. It may a significant burden on our projects.
Response: (1) Recommend participation in the CEAP for this project.	
PSE	(1) While Entities, especially some of the larger Entities, may have a lot of FR, SOER and DDR equipment already in place, the level of capability of some of the equipment may need to be upgraded. This will take time and money.
Response: (1) Recommend participation in the CEAP for this project.	

Additional Comments:

PEPCO

David Thorne

1. Do you support the new definitions for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording? If not, please explain why and provide suggested changes.

Yes

2. Do you agree with the methodology in Requirement R1 that selects the BES bus location for Sequence of Events Recording and Fault Recording? If not, please provide technical justification.

Yes

3. Are the appropriate functional entities identified in the Applicability section for PRC-002-2?

Yes

4. Do you agree with the Elements requiring Dynamic Disturbance Recording listed in Requirement R6? If not, please provide technical justification.

Yes

5. Do you agree with the VRFs/VSLs and the Drafting Teamâ€™s justification? If not, please explain why.

Yes

6. Do you agree with the Implementation Plan? If not, please explain why.

No

Question 6 Comments:

1) Implementation for Requirement R14, as presently written, applies 9 months after the standard is approved. This requirement needs to be clarified. It should only apply to those SOE, FR, and DDR devices that have been installed in accordance with, and meet the requirements of, this standard. Legacy DME equipment that may exist at one of the busses identified in R1, which does not meet the requirements of this standard, should not be subject to Requirement R14, until the equipment is upgraded, or replaced, to meet the full requirements of this standard. This clarification needs to be made, or, the implementation for R14 should be moved to coincide with the timetable for Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13.

2) The timetable for implementation of Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13 allows an entity that owns only one bus location four years to achieve compliance. However, Entities must be compliant with a reassessed list from Requirement R1, Part 1.2 or R6, Part 6.2 within three years following notification of the list. Why this discrepancy? Four years seems appropriate in both cases, in order to schedule the numerous outages necessary to install the equipment, particularly if generation units are connected to the bus.

Response: (1) Requirement R14 (now R12) is intended to only apply to data recording that meets the requirements of PRC-002. The SDT does not intend for legacy equipment that might not meet the intent of the requirement to be applicable under R14 (now R12). We have changed the Implementation Plan to reflect this by having R14 (now R12) become effective three years after approval of the standard. This coincides with the newly revised Implementation Plan whereby entities have to be 50% compliant with the data requirements within three years. We have also revised R14 (now R12) to indicate that it applies to data recording applicable under R1 (R1 and R2 combined into what is now R1) and R5 (R6 and R7 have been combined into what is now R5).

(2) The SDT believes that a reassessment involves an incremental change and will involve fewer requirements for data recording capabilities. Therefore a three year implementation is practical.

7. If you have any other comments that you haven't already mentioned above, please provide them here:
Question 7 Comments:
1) Requirement R2 should be re-written as follows: Each transmission Owner that identifies BES Elements, which are owned by other entities, at the locations established in Requirement R1 shall notify the owners of those Elements â€¦.. By adding the phrase - which are owned by other entities - eliminates the need to unnecessarily provide documentation that it notified itself of the requirement.

Response: Requirements R1 and R2 have been combined (into what is now R1). The wording "other owners" was included because the SDT considered the situation where the section of an entity doing the BES bus identification might not be the section doing the implementation of the capability.

2) Requirement R4 Part 4.1 should be re-written as follows: Phase-to-neutral voltages for each phase of either each BES line or bus. The term BES must be added to provide clarity and to be consistent with Part 4.2 and the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide voltage monitoring on non BES radial lines, or distribution transformers connected to the bus.

Response: **The Drafting Team has revised Part 3.1, and added BES to Requirement R4 (now R3) and its Parts.**

3) Requirement R8 should be re-written as follows: Each Transmission Owner shall have Dynamic Disturbance Recording (DDR), for each BES Element they own as per Requirement R7, to determine the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES radial lines, or distribution transformers connected to the bus.

Response: **The Drafting Team has added BES to Requirement R8 (now R6).**

4) Requirement R9 should be re-written as follows: Each Generator Owner shall have Dynamic Disturbance Recording (DDR), for each BES Element they own as per Requirement R7, to determine the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES station service transformers connected to the bus.

Response: **The Drafting Team has added BES to Requirement R9 (now R7).**

5) Requirement R13 Part 13.2 poses an indeterminate requirement on the size of the hard drive required to archive data. The present requirement states that the data will be retrievable for the period of 10 calendar days preceding a request. However, there is no requirement on how long after an event the request might be made. If the request was not made until six months after the event, would the data have to be retrievable for six months after the event? In order to place certainty on this data storage requirement Part 13.2 should be re-written as follows: The recorded data will be retrievable for a period of 10 calendar days following an event. This places a limit on data storage capacity and also makes it clear that a request for data must be made within 10 calendar days of the event.

Response: **(5) We have revised the language of Part 13.2 (now Part 12.2) to "Recorded data shall be retrievable for a minimum of 10 calendar days." It is not necessary for an entity to save the data for more than the 10 days specified. Because of the importance**

and need for expediency in analyzing BES system-wide disturbances, the Drafting Team decided that 10 days was a reasonable time frame to have data stored for. Requesters of data will have to be aware of the 10 calendar day requirement.

6) Requirement R14 needs to be re-written to be consistent with the intent of the requirement as expressed in the shaded box describing the Rationale for R14. As presently written, R14 requires that the Owner must both restore recording ability AND report the inability to record data to the Regional Entity. To be consistent with the Rationale, Requirement R14 should be re-written as follows: Each Transmission Owner and Generation Owner, upon discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recording (DDR) at the bus locations as per Requirement R2 and elements as per Requirement R7, shall restore the recording ability within 90 calendar days, OR , if the recording capability cannot be restored within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability.

Response: The wording in Requirement R14 (now R12) was rewritten for clarification. The bulleted items were incorporated in the R14 (now R12) wording, and "Or" was added.

7) In the Guidelines and Technical Basis in the next to last paragraph of the section on Guideline for Requirement R1 it states that there is no requirement for SOER and FR for generating units. Later in the section on Guideline for Requirement R4 it states that generator step-up transformers are excluded from fault recording. If so, why is Generator Owner listed as an applicable entity in Requirement R4? It makes sense to list them in R3, since they may own breakers connected to Transmission Owners bus, but the GSU Transformer, station service transformer, and generator itself would not qualify for Fault Recording.

Response: The Generator Owner is listed as an applicable entity in Requirement R4 (now R3) to account for the situation where a Generator Owner is responsible for BES Elements beyond a GSU high side breaker; a bus section for example.

8) There is no specific requirement for the sampling rate for SOER within the standard itself. In the Guidelines and Technical Basis section on Guideline for Requirement R5 it states that a minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for SOER. There are a vast number of microprocessor relays currently installed on the system that have a sampling rate of 16 samples per cycle for analog inputs, however, the digital inputs, which would be used for SOE recording, are only sampled every quarter cycle. Existing regional DME standards and criteria recognize this and permit these types of microprocessor relays to be acceptable for both FR and SOER applications. As such, in order to allow these devices to continue to be an acceptable application, we would suggest two requirements be added for SOER devices, similar to that included in the RFC DME criteria, that states: SOER recording equipment should be capable of determining and

recording the time that an input is received to within one quarter of an electrical cycle (or less) of input change of state. SOER recording equipment should have time stamp capability to record seconds to at least three decimal places (i.e. ss.000).

Response: The SDT believes that the quarter cycle devices mentioned are acceptable for SER but not for FR data. The additional specifications suggested are too specific for incorporation in this standard.

9) The bus selection methodology in Attachment 1 defines a single bus location as including any bus Elements at the same voltage level within the same physical location sharing a common ground grid. However, there are some substations that have multiple busses at the same voltage level within the same physical location that share a common ground grid, but are not physically connected together. They are either physically isolated from one another, or connected via a normally open tie switch or breaker. In these cases, the above definition does fit this scenario and each bus should be evaluated independently. To address this scenario perhaps the definition should be re-written as follows: A single bus location includes any bus Elements at the same voltage level that are connected together within the same physical location sharing a common ground grid.

Response: It would depend on how the buses are modeled. If the buses are modeled separately, then they should be considered as separate bus locations. The wording in the Attachment Step 1 paragraph has been revised.

PSE

Karen Silverman

1. Do you support the new definitions for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording? If not, please explain why and provide suggested changes.
Yes

2. Do you agree with the methodology in Requirement R1 that selects the BES bus location for Sequence of Events Recording and Fault Recording? If not, please provide technical justification.
No

Question 2 Comments:
The document “Mapping of Standard’s Introduction of BOT Approved PRC-002-1 to Proposed PRC-002-2” from January 2013 described line terminals above 200 kV and large generators/transmission stations which warrant this level of data gathering as they represent the backbone of the transmission system. It would be better to start with this system level and identify difficulties with collecting that data first.
For the sake of comparison, the median value of the 11 highest (short circuit) MVA PSE buses where digital fault recorders are already in place, is 6800 MVA. Lowering to the level of 1500-2500 MVA quadruples the quantity of collection sites.

Response: For the purpose of PRC-002-2, a minimum number of locations for FR and SER are required to facilitate sufficient coverage and data for analyzing large system events. Based on these concepts, the SDT developed a procedure included in Attachment 1, now entitled Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data (Requirement R1) that utilizes the maximum available calculated three phase short circuit MVA. Using this methodology helps ensure sufficient coverage while accounting for variations in size and system strength of Transmission Owners across all the Interconnections. Additionally, this methodology provides flexibility in the selection process.

The comparison provided indicates that the lower threshold would be 6800 MVA and not 1500MVA.

3. Are the appropriate functional entities identified in the Applicability section for PRC-002-2?
Yes

4. Do you agree with the Elements requiring Dynamic Disturbance Recording listed in Requirement R6? If not, please provide technical justification.
Yes

5. Do you agree with the VRFs/VSLs and the Drafting Team’s justification? If not, please explain why.
No
Question 5 Comments:
See Comments for Question 2.

6. Do you agree with the Implementation Plan? If not, please explain why.
No
Question 6 Comments:
Referring to comments to Question 2, it would be prudent to at first require a subset of the Fault Recording, SOER and DDR to be up and running and monitored for 2-3 years. Then NERC, WECC and entities can refine the standard based upon what we learn. In a nutshell, we should start small.

Response: In consultation with the NERC event analysis team, the standard requirements are developed to establish the minimum continent wide requirements for DME for adequate data capture.

7. If you have any other comments that you haven't already mentioned above, please provide them here:
Question 7 Comments:
While Entities, especially some of the larger Entities, may have a lot of FR, SOER and DDR equipment already in place, the level of capability of some of the equipment may need to be upgraded. This will take time and money.

Response: Recommend participation in the CEAP for this project.

DTE
Kathleen Black

1. Do you support the new definitions for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording? If not, please explain why and provide suggested changes.
Yes

3. Are the appropriate functional entities identified in the Applicability section for PRC-002-2?
Yes

4. Do you agree with the Elements requiring Dynamic Disturbance Recording listed in Requirement R6? If not, please provide technical justification.
No
Question 4 Comments:
The Technical Basis stated that "The 500MVA individual unit size threshold was selected because this number roughly accounts for 47% of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5% of the generating units." Also, the aggregate threshold was expected to have low impact to the number of units requiring monitoring. However, for an entity with a fleet of large generators, this MVA threshold could cover 50-75% of the fleet. Perhaps for these situations, a selection process could be developed based on strategic location within the entity's footprint, so monitoring is installed on a reasonable basis.

Response: Larger units have a significant impact on the power system that cannot be ignored in the analysis of system distrubances. The capture of each unit's data is necessary for a thorough system disturbance event analysis.

5. Do you agree with the VRFs/VSLs and the Drafting Team's justification? If not, please explain why.
Yes

6. Do you agree with the Implementation Plan? If not, please explain why.
No
Question 6 Comments:
Suggest that the stepped requirement for equipment installation be eliminated and the 100% completion in four years is the only requirement. This will allow entities to design and install equipment based on their own schedules within the four year time frame.

Response: In response to comments received, the Implementation Plan has been revised to be only two steps--three years for 50%, 5 years for 100%.

END OF REPORT