NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Meeting Agenda

Disturbance Monitoring SDT — Project 2007-11

March 30, 2009 | 1–5 p.m. EDT
March 31, 2009 | 8–5 p.m. EDT
April 1, 2009 | 8–5 p.m. EDT
FRCC Offices — The Towers at Westshore
1408 N. Westshore Blvd., Suite 1002,
Tampa, Florida 33607-4512
813-289-5644
Large Conference Room

1. Administrative

1.1. Roll Call

Stephanie Monzon will conduct roll call. Those present are listed below:

- **Navin B. Bhatt — American Electric Power (Chair)**
- Terry L. Conrad — Concurrent Technologies Corp.
- James R. Detweiler — FirstEnergy Corp.
- Barry G. Goodpaster — Exelon Business Services Company
- Steven Myers — Electric Reliability Council of Texas, Inc.
- Jeffrey M. Pond — National Grid
- Jack Soehren — ITC Holdings
- Stephanie Monzon — North American Electric Reliability Corporation
- Alan D. Baker — Florida Power & Light Company
- Bharat Bhargava — Southern California Edison Co.
- Daniel J. Hansen — Reliant Energy, Inc.
- Charles Jensen — JEA
- Tracy M. Lynd — Consumers Energy Co.
- Susan McGill — PJM
- Larry E. Smith — Alabama Power Company
- Felix Amarh — Georgia Transmission Corporation
- Robert (Bob) Millard — ReliabilityFirst Corporation
- Charlie Childs — Ametek Power Instruments
- Richard Dernbach — Los Angeles Department of Water & Power
- Willy Haffecke — Springfield Missouri City Utilities

Observers:

- Anthony Jablonski — RFC
- Richard Ferner — WAPA

2. **NERC Antitrust Compliance Guidelines**
Stephanie Monzon will review the NERC Antitrust Compliance Guidelines with the group.

3. **Review Agenda for DME Meeting**

4. **Post Mortem — Industry WebEx**
The team conducted an industry webinar on March 12, 2009. The team will discuss the feedback and follow-up questions received as a result of the webinar.

5. **First Pass Response to Comments**
The first draft of the proposed standard was posted for industry comment. The comment period closed March 18, 2009. The team will review the comment report (in the meeting materials and e-mailed to the group) and begin a first pass at responses.

6. **Discuss Technical Paper**
The team agreed to meet via conference call on February 18, 2009 to discuss the technical paper.

Top 100 Buses:

Top 100 buses — Chuck and Felix suggested that we need similar analysis for the regions but will propose language based on the FRCC top 100 buses. It may be helpful for the other members of the drafting team look into the top 100 for their regions. Create a spreadsheet to include or append to the technical paper that includes top 100 buses by region.

- Chuck will propose a spreadsheet for FRCC. This will help to collect this information for the other regions.
- Larry Smith, and Felix to determine if conclusion can be made by the data collected.
- By — February 16, 2009

February 18, 2009 — the team reviewed Felix's e-mail and data and agreed that collecting data from other regions would be helpful in supporting the team's thresholds — top 100 buses and/or 10,000 MVA short circuit level.

Major Event Analysis:

Include event analysis experience and any conclusions that may be drawn from historical events (the August 14 blackout, etc.). Navin Bhatt and Tracy will work on proposed language and may reach out to Bob Cummings.

- Chuck indicated that the NERC Blackout report on the Web site (major outages) does not include facilities under 200kV that contributed to the outages. Chuck will send the report to Navin.
- Navin and Tracy will work on collecting more information for this section (by February 16, 2009).

February 18, 2009 — Navin will call Bob C. to discuss his concerns and comments on the draft standard. Tracy will discuss the need to better understand the NERC definition of a major disturbance (what constitutes a major disturbance). Tracy will look through the "Major Disturbances of the Year" reports published by NERC (yearly) for data that would support the technical paper.

Navin will send out a 2002 Disturbance Report to the team (as a sample of the reports that will be reviewed).

Monitoring Special Protection Systems and Remedial Action Schemes:
Include the impact of under voltage load shedding and special protection system on DME thresholds. Richard and Larry Smith will do some research on this to determine if it is in fact impactful.

February 18, 2009 — The team agreed that UVLS is applicable at the distribution level and not appropriate for the technical paper as a justification for the DME standard. The team did decide to address monitoring special protection system and remedial action schemes.

Critical Clearing Times:
Include critical clearing time (on bus level very short) — recognized locations where we need to reduce back up clearing. Chuck will do some research this and try to collect information.

- Chuck will work on the clearing times for FRCC. This will help to collect this information for the other regions.

February 18, 2009 — Chuck and Felix will send out a spreadsheet with critical clearing column (breaker failure backup clearing time) but Chuck notes that the data doesn't indicate a strong correlation with critical buses.

The team will review the data for FRCC provided by Chuck and the date provided by Felix to determine if there is a correlation. The team will then determine if it should be included in the technical paper.

Jack will provide MVA spread (number of elements) for lower Michigan.

Stability:
Felix to send an email that elaborates on adding this topic to the technical paper.

2/18 – Felix, Chuck and Larry will work on the language to be included in the technical paper.

Pmu installation — Navin:
Some team members do not think that it may be entirely appropriate to include pmu data into the technical paper since pmus are not included in the standard. This may cause confusion if included in the technical paper but not in the standard.

Navin will collect some data for the team to look over (number of installations and at kV level) the team will decide whether or not to include in the technical paper after reviewing some of the data that will be collected.

7. Action Items

Action Items	Status:	Assigned To:
The group must resolve how to develop requirements for maintenance and testing of disturbance monitoring equipment (DME). Possible options include, adding maintenance and testing requirements to the draft PRC-002 standard, asking the Standards Committee to transfer the maintenance and testing requirements to the standard drafting team (SDT) for Project 2007-17 Protection System Maintenance and Testing, or some other solution. Ultimately, the maintenance and testing requirements for DME should “look and feel” like the maintenance and testing requirements developed by the SDT for Project 2007-17 Protection System Maintenance and Testing.	**In Progress** **This issue will be addressed in the comment form to solicit industry feedback on how to proceed.** **Discussed at the 12/08/08 call:** **The team reviewed the status of the issue clarifying that the team was going to post the standard and solicit industry feedback on omitting these requirements. The team would use this feedback to propose an alternate to the SC or NERC staff – possibly create a supplemental to SAR to the Maintenance project.**	All
Navin to lead a small group in drafting the **measures** for the requirements. Jack Soehren, Felix Amarh, and Barry Goodpaster volunteered to assist Navin.	**Closed**	Navin Bhatt, Jack Soehren, Felix Amarh, and Barry Goodpaster
Steve Myers, Larry Brusseau, and Bob Millard to draft the **VRFs and VSLs.**	**Will Remain Open**	Steve Myers, Larry Brusseau, and Bob Millard
Chuck, Jim and Alan will be proposing language for R5.1 and R5.2.	**Completed**	Chuck, Alan and Jim.
Willy will review the comment form to ensure that references to the standard are still correct.	**Completed**	Willy H.

Action Items	Status:	Assigned To:
Jim will look over the mapping form to ensure that references to the standard are still correct.	**Completed**	Jim D.

8. Next Steps

9. 2009 Schedule

Date and Time	Location	Comments
February 18, 2009	Conference Call	To discuss the technical paper
March 2, 2009	Conference Call	Webinar presenters and NERC staff required on this call to prep for the webinar
March 12, 2009 11 a.m.–12:30 p.m. EST	Industry Webinar	Need to confirm date with team and speakers
March 30, 2009 — 1–5 p.m. EST March 31, 2009 — 8 a.m.–5 p.m. EST April 1, 2009 — 8 a.m.–5 p.m. EST	FRCC Offices Tampa, FL	Confirmed by Chuck.

10. Other

11. Adjourn

Disturbance Monitoring Standard Drafting Team

Chairman	Navin B. Bhatt, Ph.d., PE Manager - Advanced Transmission Studies and Technologies	American Electric Power 825 Tech Center Drive Third Floor Gahanna, Ohio 43230-8250	(614) 552-1660 (614) 552-1676 Fx nbbhatt@aep.com
	Felix Amarh, PhD Group Leader, System Protection	Georgia Transmission Corporation 2100 East Exchange Place Tucker, Georgia 30084	(770) 270-7567 (770) 270-7775 Fx felix.amarh@ gatrans.com
	Alan D. Baker Principal Engineer	Florida Power & Light Co. 700 Universe Boulevard Juno Beach, Florida 33408	(561) 694-4787 alan_d_baker@ fpl.com
	Bharat Bhargava	Southern California Edison Co. 2131 Walnut Grove Avenue Rosemead, California 91770	(626) 302-8684 bharat.bhargava@ sce.com
	Charlie Childs	Ametek Power Instruments 255 North Union Street Rochester, New York 14605	(585) 238-4001 charlie.childs@ ametek.com
	Richard Dernbach Manager of System Protection and SCADA RTU	Los Angeles Department of Water & Power 1630 N. Main Street Building 7, Room 306 Los Angeles, California 90012	(213) 367-7292 (213) 267-7302 Fx richard.dernbach@ ladwp.com
	James R. Detweiler	FirstEnergy Corp. 76 South Main Street Akron, Ohio 44308	(330) 761-7797 jrdetweiler@ firstenergycorp.com
	Barry G. Goodpaster	Exelon Business Services Company Two Lincoln Centre 9th Floor Oakbrook Terrace, Illinois 60181	(630) 437-2748 barry.goodpaster@ exeloncorp.com
	Willy Haffecke Assistant Manager Electic T&D - Substations	City Utilities of Springfield ,	(417) 831-8332 william.haffecke@ cityutilities.net
	Daniel J. Hansen Consulting Engineer	Reliant Energy, Inc. 1000 Main Street, 1674D Houston, Texas 77002	(713) 488-7271 (713) 497-9280 Fx dhansen@ reliant.com
	Tracy M. Lynd	Consumers Energy Co. 1945 W. Parnall Road Jackson, Michigan 49201	(517) 788-0395 tmlynd@ cmsenergy.com
	Susan L. McGill	PJM Interconnection, L.L.C. 955 Jefferson Avenue Norritown, Pennsylvania 19403	(610) 666-4573 mcgils@pjm.com
	Robert W. Millard Director - Standards	ReliabilityFirst Corporation 320 Springside Drive Suite 300 Akron, Ohio 44333	(330) 697-4032 (330) 456-3648 Fx bob.millard@ rfirst.org

	H. Steven Myers Manager of Operating Standards	Electric Reliability Council of Texas, Inc. 2705 West Lake Drive Taylor, Texas 76574-2136	(512) 248-3077 (512) 248-3055 Fx smyers@ercot.com
	Jeffrey M. Pond Senior Engineer	National Grid 25 Research Drive Westborough, Massachusetts 01532	(508) 389-2553 (315) 477-7148 Fx jeff.pond@ us.ngrid.com
	Larry E. Smith Team Leader - Transmission Automation and Analysis	Alabama Power Company 600 N. 18th Street P.O. Box 2641 Birmingham, Alabama 35291	(205) 257-3270 (205) 257-4684 Fx lesmith@ southernco.com
	Jack Soehren	ITC Holdings 27175 Energy Way Novi, MI 48377	(248) 946-3290 jsoehren@ itctransco.com
Standards Process Manager	Maureen E. Long Standards Process Manager	North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx maureen.long@ nerc.net
NERC Manager of Regional Standards	Stephanie Monzon Manager of Regional Standards	North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx stephanie.monzon@ nerc.net
NERC Staff	Julia Souder Director, Inter-Governmental Relations	North American Electric Reliability Corporation 1120 G Street, N.W. Suite 990 Washington, D.C. 20005-3801	(202) 393-3998 (202) 393-3955 Fx julia.souder@ nerc.net
NERC Manager of Standards Development	David Taylor Manager of Standards Development	North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721	(609) 452-8060 (609) 452-9550 Fx david.taylor@ nerc.net

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Antitrust Compliance Guidelines

I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.

- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.
- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

III. Activities That Are Permitted

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Consideration of Comments on 1st Draft of PRC-002-2 — Disturbance Monitoring and Reporting Requirements — Project 2007-11

The Disturbance Monitoring Standard Drafting Team thanks all commenters who submitted comments on the proposed first draft of reliability standard PRC-002-2 — Disturbance Monitoring and Reporting Requirements. This standar0064 were posted for a 45-day public comment period from February 2, 2009 through March 18, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 62 sets of comments, including comments from more than 130 different people from over 70 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Disturbance_Monitoring_Project_2007-11.html

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, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

1. **The SDT has considered the "fill in the blank" items that are specified in the NERC Board approved standard PRC-002-1 that the Regional Reliability Organizations were required to develop "procedures and requirements" for the entities to meet. The SDT also considered all the directives specified in FERC approved PRC-018-1. The SDT is proposing to change the "fill in the blank" characteristics into entity specific requirements and merge them with the PRC-018-1 requirements. The new proposed standard PRC-002-2 contains all requirements related to disturbance monitoring with the exception of maintenance and testing (see Question #3 below). Do you agree with the SDT's proposal to develop and merge all disturbance monitoring requirements into a new PRC-002-2?** 12
2. **The SDT has developed a mapping document showing the requirements in PRC-002-1 and PRC-018-1 and where, in proposed PRC-002-2, those requirements are reflected (except maintenance and testing – see Question #3 below). Do you agree that the SDT has reflected all the appropriate requirements of PRC-002-1 and PRC-018-1 in the proposed PRC-002-2?** 18
3. **The SDT recommends that the maintenance and testing requirements for disturbance monitoring equipment belong in another standard. Do you agree with the SDT's proposal to exclude these requirements from PRC-002-2 and include them in another standard, either through the creation of a SAR or by assigning these requirements to an existing project?** 24
4. **The criteria used by the SDT in selecting locations for monitoring/recording Disturbance data is based on minimum number of elements (lines, transformers, etc.) or minimum amount of generation at a specific location. This approach facilitates the measurement of compliance to the requirements. Do you agree with the SDT's approach? Please provide specific comments, examples or recommendations.** 33
5. **In developing the Disturbance data requirements the SDT decided to focus on transmission voltage levels of 200 kV and above, generators 500 MVA and above, and generating stations 1500 MVA and above based on expected impact to the interconnected system. It is the team's strong belief that application of requirements below these values to include the entire BES will require significant additional resources, while adding little value.** 43

5.1 Do you agree with these nameplate values? Please provide supporting documentation for these values. If not, please propose alternate values and their technical basis. 43

5.2 In part, Requirement R5 states that Fault Recording data shall be recorded at generating plants connected at 200 kV and above when a generator has a nameplate capacity of 500 MVA or higher or when there is an aggregate plant total of 1500 MVA or higher. Do you agree with these values? Please provide supporting documentation for these values. If not, please propose alternate values and their technical basis. 52

5.3 Requirement R7 states that DDR data shall be recorded or derivable for all substations having a total of seven or more transmission lines connected at 200 kV or above. Do you agree with these values? Please provide supporting documentation for these values. If not, please propose alternate values and their technical basis. 59

6. **Requirement R3 states that Transmission Owners and Generator Owners shall record the time stamp or have a process in place to derive the time stamp to within four milliseconds of input received for the change in circuit breaker position (open/close) Do you agree with this value? If no, propose an alternate value and please provide technical basis.** 67

Requirements related to Sequence of Events 73

7. Do you agree with the other Sequence of Events requirements under R1 through R3 of the proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you. 73
Requirements related to Fault Recording 82
8. Requirement R6 states that Fault Recording data shall include a pre trigger record length of at least two cycles and: a post trigger length of at least 50 cycles, or the first three cycles and the final cycle of an event. Do you agree with the requirement? If not, please propose alternate values or requirements and provide rationale. 82
Requirements related to Fault Recording 90
9. Do you agree with the other Fault Recording requirements in R4 through R6 of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you. 90
Requirements related to Dynamic Disturbance Recording 101
10. Requirement R7 states that a DDR which is required at a substation meeting the location requirement shall be considered optional if a DDR meeting all of the requirements of R7.1, R7.2, R7.3 and R7.4 is found to be located one or two substations away. Do you agree with this option found in Requirement R7? If no, provide rationale. 101
Requirements related to Dynamic Disturbance Recording 107
11. Requirement R8 states that Generator Owners shall record or have a process in place to derive DDR data for generating plants with an aggregate of 1500 MVA nameplate rating or higher. Do you agree with these values? Please provide supporting documentation for these values or (if you disagree with the values) alternate values and their technical basis. 107
Requirements related to Dynamic Disturbance Recording 114
12. Do you agree with the other Dynamic Disturbance Recorder requirements in R7 through R11 of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you. 114
General Questions 125
13. Do you agree with the Other Disturbance Monitoring Requirements R12 and R13 of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you. 125
General Questions 132
14. Are you aware of any regional variances that would be required as a result of the proposed standard? 132
General Questions 137
15. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? 137
General Questions 142
16. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain. 142
General Questions 155
17. Do you agree with the implementation plan as proposed by the SDT? If no, provide a plan that would be acceptable to you and provide rationale. 155
General Questions 164
18. The standard is proposing a definition for "Substation" based on the IEEE definition. Do you agree that there is sufficient misunderstanding of this term to warrant a definition? If so, do you agree that the IEEE definition is the most appropriate definition? 164

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
2.	Rick White	Northeast Utilities	NPCC	1
3.	Randy MacDonald	New Brunswick System Operator	NPCC	2
4.	Manny Couto	National Grid	NPCC	1
5.	Ralph Rufrano	New York Power Authority	NPCC	5
6.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
7.	Michael Sonnelitter	NextEra Energy	NPCC	5
8.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
9.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Bruce Metruck	New York Power Authority	NPCC	6
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	Brian Evans-Mongeon	Utility Services	NPCC	6
14.	Michael Gildea	Constellation Energy	NPCC	6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

15.	Xiadong Sun	Ontario Power Generation Inc.	NPCC	5
16.	Lee Pedowicz	NPCC	NPCC	10
17.	James Ingleson	New York Independent System Operator	NPCC	2
18.	Paul Kiernan	New York Independent System Operator	NPCC	2
19.	Donald E. Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
20.	James Delorme	Nova Scotia Power, Inc.	NPCC	2
21.	Gerry Dunbar	NPCC	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Anita Lee	AESO	WECC	2
2.	Patrick Brown	PJM	RFC	2
3.	Bill Phillips	MISO	RFC	2
4.	Steve Myers	ERCOT	ERCOT	2
5.	Jim Castle	NYISO	NPCC	2
6.	Matt Goldberg	ISO-NE	NPCC	2
7.	Charles Yeung	SPP	SPP	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Shawn Jacobs	SPP System Protection and Control Working Group	X	X	X							X
4.	Group	Donald Davies	Members of the WECC Disturbance Monitoring Work Group										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Pink	TSGT	WECC	1
2.	Doug Selin	APS	WECC	1, 3, 5
3.	Gary Kopps	NV Energy	WECC	1, 3, 5
4.	Peter Mackin	USE	WECC	
5.	Steve Rueckert	WECC	WECC	NA

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	6. Donald Davies	WECC	WECC NA										
	7. Kenneth Wilson	WECC	WECC NA										
5.	Group	Jim Busbin	Southern Company - Transmission	X		X		X					
6.	Group	Phillip R. Kleckley	SERC Engineering Committee Planning Standards Subcommittee			X							
7.	Group	Steve Waldrep (Co-Chair), Joe Spencer (SERC staff)	SERC Protection and Controls Sub-committee										X
8.	Group	Sandra Shaffer	PacifiCorp	X		X		X	X				

Group 5 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Raymond Vice	Southern Company Services	SERC	1
2.	Hugh Francis	Southern Company Services	SERC	1
3.	J. T. Wood	Southern Company Services	SERC	1
4.	Marc Butts	Southern Company Services	SERC	1
5.	Bill Shultz	Southern Company Services	SERC	5
6.	Phil Winston	Georgia Power Company	SERC	3
7.	Steve Bennett	Georgia Power Company	SERC	3

Group 6 additional members:

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	Scott Goodwin	Midwest ISO	SERC	2
4.	Carter Edge	SERC Reliability Corp	SERC	10
5.	Pat Huntley	SERC Reliability Corp	SERC	10
6.	Bob Jones	Southern Co. Services	SERC	1
7.	David Marler	TVA	SERC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Jalal Babik	Dominion	X				X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc	RFC	5, 6
2.	Mike Garton	Dominion Resources Services, Inc	NPCC	5, 6
3.	Tommy Owens	ELECTRIC TRANSMISSION RELIABILITY	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Burns	Transmission Technical Operations	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2.	Bill Duge	FE	RFC	5
3.	Jim Detweiler	FE	RFC	1
4.	Art Buanno	FE	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Silvia Parada-Fortun	Florida Power & Light	X		X		X					
13.	Group	George P. Nino	Los Angeles Department of Water & Power	X				X				X	
14.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Gerou	MP	MRO	1, 3, 5, 6
2.	Neal Balu	WPS	MRO	3, 4, 5, 6
3.	Terry Bilke	MISO	MRO	2
4.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
5.	Ken Goldsmith	ALTW	MRO	4

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

6. Jim Haigh	WAPA	MRO	1, 6
7. Terry Harbour	MEC	MRO	1, 3, 5, 6
8. Joseph Knight	GRE	MRO	1, 3, 5, 6
9. Scott Nickels	RPU	MRO	3, 4, 5, 6
10. Dave Rudolph	BEPC	MRO	1, 3, 5, 6
11. Eric Ruskamp	LES	MRO	1, 3, 5, 6
12. Pam Sordet	XCEL	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Ed Taylor	PG&E System Protection	X									

Additional Member	Additional Organization	Region	Segment Selection
1. Vahid Madani	PG&E	WECC	1
2. Steven Ng	PG&E	WECC	1
3. Chifong Thomas	PG&E	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Individual	Joe Uchiyama	US Bureau of Reclamation					X				X	
17.	Individual	Robert W. Cummings - Director of Event Analysis	NERC										
18.	Individual	Jian Zhang	TransAlta					X					
19.	Individual	Joe White	Grant County PUD	X		X							
20.	Individual	Jeremiah Stevens	NYISO		X								
21.	Individual	Gary Preslan/Bill Middaugh	Tri-State Generation and Transmission Association	X		X		X	X				
22.	Individual	Russell A. Noble	Cowlitz County PUD	X		X	X	X					
23.	Individual	Adam Menendez	Portland General Electric	X		X	X	X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
24.	Individual	Dania J. Colon	Progress Energy Florida	X		X		X					
25.	Individual	Catherine Koch	Puget Sound Energy	X									
26.	Individual	Lance Irwin	Schneider Electric										
27.	Individual	Dan Rochester	Independent Electricity System Operator		X								
28.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
29.	Individual	Michael Sonnelitter	NextEra Energy Resources (formerly FPL Energy)					X					
30.	Individual	Manuel Couto	National Grid	X		X	X						
31.	Individual	Kris Manchur	Manitoba Hydro	X		X		X	X				
32.	Individual	John Gyrath	Exelon Generation LLC					X					
33.	Individual	Scott Helbing	NV Energy	X		X	X	X					
34.	Individual	Dave Szulczewski	DTE Energy/Detroit Edison			X							
35.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
36.	Individual	Jack Soehren	ITC Transmission, METC	X									
37.	Individual	Alan Gale	City of Tallahassee (TAL)	X		X		X					
38.	Individual	Alvin C. Depew	PHI (PEPCO Holdings Inc.)	X		X							
39.	Individual	Richard Salgo	NV Energy (fka Sierra Pacific	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
			Resources)										
40.	Individual	John Hernandez	Salt River Project	X		X		X				X	
41.	Individual	John F. Hauer	Pacific Northwest National Laboratory									X	
42.	Individual	Jerry Blackley	Progress Energy Carolina, Inc.	X		X		X					
43.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
44.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
45.	Individual	Steve Rueckert	WECC										X
46.	Individual	Ed Davis	Entergy Services, Inc	X		X		X	X				
47.	Individual	Rick White	Northeast Utilities	X									
48.	Individual	Randy Schimka	San Diego Gas and Electric Co.	X		X							
49.	Individual	Gregory Campoli	New York Independent System Operator		X								
50.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
51.	Individual	Douglas Selin	Arizona Public Service Co.	X		X		X					
52.	Individual	Charles J. Jensen	JEA	X		X		X				X	
53.	Individual	John Tolo	Tucson Electric Power	X									
54.	Individual	Anita Lee	Alberta Electric System Operator		X								

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
55.	Individual	Murty Yalla	Beckwith Electric Co										
56.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
57.	Individual	Armin Klusman	CenterPoint Energy	X									
58.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
59.	Individual	R. Peter Mackin, P.E.	Utility System Efficiencies, Inc.										
60.	Individual	Dan Buchanan	British Columbia Transmission Corporation	X									
61.	Individual	Tim Hinken	Kansas City Power & Light	X		X		X	X				
62.	Individual	Richard Curtner	PNM										

1. The SDT has considered the "fill in the blank" items that are specified in the NERC Board approved standard PRC-002-1 that the Regional Reliability Organizations were required to develop "procedures and requirements" for the entities to meet. The SDT also considered all the directives specified in FERC approved PRC-018-1. The SDT is proposing to change the "fill in the blank" characteristics into entity specific requirements and merge them with the PRC-018-1 requirements. The new proposed standard PRC-002-2 contains all requirements related to disturbance monitoring with the exception of maintenance and testing (see Question #3 below). Do you agree with the SDT's proposal to develop and merge all disturbance monitoring requirements into a new PRC-002-2?

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	Yes	We assumed that the question refers to the merging of Standards PRC-002-1 and PRC-018-1.
Response:		
IRC Standards Review Committee	Yes	
SPP System Protection and Control Working Group	Yes	Please clarify the term "entity specific requirements" in Question #1.
Response:		
Members of the WECC Disturbance Monitoring Work Group	Yes	
Southern Company - Transmission	Yes	Southern Company agrees with the comments made by the SERC Protection and Control Subcommittee (PCS). Generally, the determination of "where" to locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid. These stability evaluations should be made according

Organization	Yes or No	Question 1 Comment
		to an overall NERC defined methodology. In the absence of a NERC defined methodology, a SAR should be introduced to produce one.
Response:		
SERC Engineering Committee Planning Standards Subcommittee	Yes	
SERC Protection and Controls Sub-committee	Yes	But we believe that the regional "Stability" group needs to decide on the locations of the DDR's based on a NERC defined methodology.
Response:		
PacifiCorp	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	Is there a purpose to the analyses proposed. How much detail is really needed?
Response:		
FirstEnergy	Yes	We agree that it will be beneficial to consolidate these standards into one document.
Response:		
Florida Power & Light	Yes	A single standard to define the installation application of DMEs makes good sense.
Response:		
Los Angeles Department of Water & Power	Yes	

Organization	Yes or No	Question 1 Comment
MRO NERC Standards Review Subcommittee	Yes	
PG&E System Protection	Yes	
US Bureau of Reclamation	Yes	It is good idea to make a single document to cover all DME requirements
Response:		
NERC	Yes	
TransAlta		
Grant County PUD	Yes	
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	A single standard addressing disturbance monitoring is GREATLY appreciated. This will simplify compliance efforts.
Response:		
Portland General Electric	Yes	
Progress Energy Florida	Yes	
Puget Sound Energy	Yes	
Schneider Electric	Yes	

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid	Yes	
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	
DTE Energy/Detroit Edison	Yes	
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	Any time we can combine similar requirements into the same standard we are better off.
Response:		
PHI (PEPCO Holdings Inc.)	Yes	No need for different standards to cover DM.
Response:		
NV Energy (fka Sierra Pacific Resources)	Yes	

Organization	Yes or No	Question 1 Comment
Salt River Project	Yes	
Pacific Northwest National Laboratory	Yes	The new standard should at least allude to the context within which the data will be employed, and to the data quality (resolution, accuracy, band shape) that is requisite to this usage. (Data rates derive from the needed quality.) To do this for DDR devices the new standard must somehow encapsulate core issues that are addressed in documents [21,125,221]. [21] Integrated Dynamic Information for the Western Power System: WAMS Analysis in 2005, J. F. Hauer, W. A. Mittelstadt, K. E. Martin, J. W. Burns, and Harry Lee in association with the Disturbance Monitoring Work Group of the Western Electricity Coordinating Council. Chapter 14 in the Power System Stability and Control volume of The Electric Power Engineering Handbook, edition 2, L. L. Grigsby ed., CRC Press, Boca Raton, FL, 2007. [125] WECC Disturbance/Performance Monitor Equipment: Proposed Standards for WECC Certification and Reimbursement, Principal Investigator K. E. Martin. Draft report of the WECC Disturbance Monitoring Work Group, March 17, 2004.[221] PMU System Testing and Calibration Guide. NASPI report of the Performance & Standards Task Team (PSTT), December 30, 2007.
Response:		
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie	Yes	We assumed that the question refers to the merging of Standards PRC-002-1 and PRC-018-1.
Response:		
Brazos Electric Power Cooperative, Inc.	Yes	
WECC	Yes	I also agree with changing the fill in the blank characteristics into entity specific requirements
Response:		
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric	Yes	

Organization	Yes or No	Question 1 Comment
Co.		
New York Independent System Operator	Yes	
E.ON U.S.	Yes	
Arizona Public Service Co.	Yes	
JEA	Yes	
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Duke Energy	Yes	
CenterPoint Energy		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	

2. The SDT has developed a mapping document showing the requirements in PRC-002-1 and PRC-018-1 and where, in proposed PRC-002-2, those requirements are reflected (except maintenance and testing – see Question #3 below). Do you agree that the SDT has reflected all the appropriate requirements of PRC-002-1 and PRC-018-1 in the proposed PRC-002-2?

Summary Consideration:

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	Requirement R3.2.1 in PRC-002-1 lists a technical requirement for recording devices installed after Jan. 1, 2009. Requirement R10 in PRC-002-2 applies to the installation of DDR devices after Jan. 1, 2011. Why was the date changed? In PRC-002-1 R4.5 refers to naming data files. In PRC-002-2 the naming of data files was moved to Section D, Compliance, Subsection 1.5 Additional Compliance Information. It does not appear in the Requirement Section. Data file naming, and data file formatting should be a requirement.
Response:		
IRC Standards Review Committee	Yes	
SPP System Protection and Control Working Group	Yes	
Members of the WECC Disturbance Monitoring Work Group		
Southern Company - Transmission	Yes	No further comment.
Response:		
SERC Engineering Committee Planning Standards	Yes	

Organization	Yes or No	Question 2 Comment
Subcommittee		
SERC Protection and Controls Sub-committee	Yes	Except possible impact based on protection scheme used when three phase line or bus potential are not available.
Response:		
PacifiCorp		
Dominion	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	No	We agree that maintenance and testing requirements might eventually be more appropriately located in another standard at some future time. However, in order to retain the current approved standard requirements that include maintenance and testing, these requirements need to be included in this standard until such time they can be transferred to another standard. Otherwise, the SDT should provide a technical justification as to why these requirements are no longer needed for this type of equipment.
Response:		
Florida Power & Light	Yes	
Los Angeles Department of Water & Power	Yes	
MRO NERC Standards Review Subcommittee	No	In the proposed PRC-002-2 R8 (DDR), why did the SDT drop the requirement for single generators to be 500 MVA or higher as noted in the Applicability section 4.2
Response:		
PG&E System Protection	Yes	
US Bureau of Reclamation	Yes	

Organization	Yes or No	Question 2 Comment
NERC	Yes	
TransAlta		
Grant County PUD		
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	
Portland General Electric		
Progress Energy Florida	Yes	
Puget Sound Energy	Yes	
Schneider Electric	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	

Organization	Yes or No	Question 2 Comment
Exelon Generation LLC	Yes	
NV Energy	Yes	
DTE Energy/Detroit Edison	Yes	
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	No	Current "Requirements" R4 should NOT be moved to the Compliance section. This will result in missing requirement. This is hiding a requirement in Compliance or Monitoring and is a practice we need to get out of! Compliance sections 1.3.1, 1.3.2, and 1.5.1 need to be moved back into the Requirements section!
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project		
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	No	Requirement R3.2.1 in PRC-002-1 lists a technical requirement for recording devices installed after Jan. 1, 2009. Requirement R10 in PRC-002-2 applies to the installation of DDR devices after Jan. 1, 2011. Why was the date changed? In PRC-002-1 R4.5 refers to naming data files. In PRC-002-2 the naming of data files was moved to Section D, Compliance, Subsection 1.5 Additional Compliance Information. It does not appear in the Requirement Section. Data file naming, and data file formatting should be a requirement.

Organization	Yes or No	Question 2 Comment
Response:		
Brazos Electric Power Cooperative, Inc.	Yes	
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	No	Requirement R3.2.1 in PRC-002-1 lists a technical requirement for continuous recording for DDRs installed after Jan. 1, 2009. Requirement R10 in PRC-002-2 delays this requirement until Jan. 1, 2011. Why was the date changed? In PRC-002-1, R4.5 refers to naming data files. In PRC-002-2 the naming of data files was moved to Section D, Compliance, Subsection 1.5 Additional Compliance Information. It does not appear in the Requirement Section. Will this be enforced as a "Requirement"?
Response:		
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
E.ON U.S.	No	The SDT appears to have exceeded what is necessary by requiring all GOs and TOs to provide this information. Compliance with these draft requirements promises to be extremely costly. It is a major undertaking for all Generation Operator's across the nation to install synchronized disturbance monitoring devices capable of recording down to +/- 2 milliseconds. Also, there should be allotted more time for the engineering and installation of new hardware, etc. than that provided in the proposed timetable
Response:		
Arizona Public Service Co.		
JEA	Yes	Good job on mappring all the requirements!!

Organization	Yes or No	Question 2 Comment
Response:		
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Duke Energy	Yes	
CenterPoint Energy		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		
Kansas City Power & Light	Yes	
PNM	Yes	

3. The SDT recommends that the maintenance and testing requirements for disturbance monitoring equipment belong in another standard. Do you agree with the SDT's proposal to exclude these requirements from PRC-002-2 and include them in another standard, either through the creation of a SAR or by assigning these requirements to an existing project?

Summary Consideration:

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	Yes	We agree that the maintenance and testing should be in another standard. However, we are concerned that the time to develop a separate standard would introduce a "time gap" when there would be an in force Disturbance Monitoring Standard, with no document in place addressing maintenance and testing.
Response:		
IRC Standards Review Committee	Yes	The SRC agrees with the proposal to exclude maintenance and testing from this standard.
Response:		
SPP System Protection and Control Working Group	Yes	Recommend to include these requirements in PRC-005 (with time line) or a specific action plan with time line (parallel to PRC-002-2) to include in another standard.
Response:		
Members of the WECC Disturbance Monitoring Work Group	Yes	
Southern Company - Transmission	No	Southern Company does not agree with separating from this standard maintenance and testing requirements for disturbance monitoring equipment for inclusion in another standard. We feel that separating those requirements needlessly complicates an entity's ability to monitor and maintain compliance with the standard(s). We realize the drafting team is handling a set of very technical and complex issues in this disturbance monitoring and reporting standard and we urge them to keep the standard simple where possible.

Organization	Yes or No	Question 3 Comment
Response:		
SERC Engineering Committee Planning Standards Subcommittee	Yes	
SERC Protection and Controls Sub-committee	No	Prefer that M&T continue to be contained within this standard.
Response:		
PacifiCorp	Yes	
Dominion	No	Prefer M&T to be contained within this standard. Do not move DME M&T to a totally new standard.
Response:		
Bonneville Power Administration	Yes	
FirstEnergy	No	We agree that maintenance and testing requirements might eventually be more appropriately located in another standard at some future time. However, in order to retain the current approved standard requirements that include maintenance and testing, these requirements need to be included in this standard until such time they can be transferred to another standard. Otherwise, the SDT should provide a technical justification as to why these requirements are no longer needed for this type of equipment.
Response:		
Florida Power & Light	Yes	Maintenance can be defined in another standard, however, PRC-002 should specifically allow for missing data for a given event since triggering may be inadequate and equipment can be down for maintenance/repair.
Response:		
Los Angeles Department of	Yes	

Organization	Yes or No	Question 3 Comment
Water & Power		
MRO NERC Standards Review Subcommittee	Yes	Having a separate maintenance and testing standard may be easier to administrate for most utilities.
Response:		
PG&E System Protection	Yes	
US Bureau of Reclamation	No	As I mentioned in item-1 above, all DME requirements should be in one document. The maintenance and testing requirements for DME should be in one document.
Response:		
NERC	Yes	They should be included in PRC-005 -- Transmission Protection System Maintenance and Testing
Response:		
TransAlta		
Grant County PUD	Yes	
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	Maintenance and testing (M&T) separation is good as long as there is no text in either standard referring back to another standard. So, PRC-002-2 has recording parameters defined as it should; the M&T standard should only require the equipment to be maintained (keep it working) and tested (it works as programmed). If the installed equipment does not meet the requirements of PRC-002-2 either by wrong choice of equipment or poor programming, then there is only a PRC-002-2 violation, not a PRC-M&T standard violation as long as the equipment was maintained and tested. In other words, a single violation should only incur one standard being violated; standard verbiage should avoid the possibility of double jeopardy. I would suggest that the same SDT

Organization	Yes or No	Question 3 Comment
		for PRC-002-2 work on the M&T standard.
Response:		
Portland General Electric	Yes	
Progress Energy Florida	No	Requirements related to DME equipment maintenance should not be included in the PRC-005 standard because the importance of DME equipment does not warrant the same high level attention as Protection Systems. PRC-002-2 seems to be a more logical place.
Response:		
Puget Sound Energy	Yes	
Schneider Electric	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	AEP is agreeable that the maintenance and testing belongs in another standard. Currently, there is a maintenance and testing team at work on standard PRC-005-1 (Project 2001-17) wherein these requirements would fit well.
Response:		
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	

Organization	Yes or No	Question 3 Comment
NV Energy	Yes	
DTE Energy/Detroit Edison	No	One standard should cover all issues relating to disturbance monitoring. Also, since DMEs are monitoring and not protective devices, is it necessary to specify maintenance/testing requirements? Requirements already in the Standard for data submittals would necessitate maintaining the availability of the DMEs.
Response:		
Wisconsin Electric	Yes	
ITC Transmission, METC	No	The FERC-approved PRC-018-1 requires a maintenance and testing program for DME and it should be included in the new PRC-002-2.
Response:		
City of Tallahassee (TAL)	Yes	It would be ideal if ALL Maintenance and Testing requirements were in one standard!
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	The maintenance and testing requirements do not belong in this Standard. However, since the devices' performance is not a system protection function, I believe that there should not be any NERC Standards/Requirements for maintenance and testing requirements. If deemed necessary, it would suffice to have a performance standard that requires that the appropriate data be available and collected from the disturbance monitoring equipment following system events, rather than imposing another set of maintenance requirements on the industry. To the extent that some of the disturbance monitoring functions are carried out by actual protective relays; example, SEL relays, then the maintenance of the protective functions of those relays will already be covered in PRC-005.
Response:		
Salt River Project	Yes	

Organization	Yes or No	Question 3 Comment
Pacific Northwest National Laboratory	Yes	Testing requirements must, among other things, verify that the hetterogenous sets of DDR data can be integrated and processed in a timely manner--e.g., the DDR types must in some sense be "interoperable." This will lead to desirable performance targets that should be incorporated into standards for future DDR installations. (See various documents on the WECC WAMS.)
Response:		
Progress Energy Carolina, Inc.	No	Requirements related to DME equipment maintenance should not be included in the PRC-005 standard because the importance of DME equipment does not warrant the same high level attention as Protection Systems. PRC-002-2 seems to be a more logical place.
Response:		
Hydro-Québec TransEnergie (HQT)	Yes	We agree that the maintenance and testing should be in another standard. However, we are concerned that the time to develop a separate standard would introduce a "time gap" when there would be an in force Disturbance Monitoring Standard, with no document in place addressing maintenance and testing.
Response:		
Brazos Electric Power Cooperative, Inc.	Yes	
WECC	No	I agree with the notion that the maintenance and testing requirements for disturbance monitoring equipment belong in another standard. However, I am concerned that if they are not initially included PRC-002-2, that for a while we run the risk of not having a standard that requires maintenance and testing of disturbance monitoring equipment. I am concerned that an effort through creation of a SAR or assigning these to an existing project may take longer than completion of the proposed PRC-002-2. Would it be possible to retain the existing requirment for the applicable entity to have a maintenance and testing program that includes maintenance and testing intervals and their basis, and a summary of maintenance and testing procedures (PRC-018, R6) in PRC-002-2 until such time that a replacement standard was approved, and then drop the requirement from PRC-002-2?
Response:		

Organization	Yes or No	Question 3 Comment
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
E.ON U.S.	No	All requirements relating to DME (disturbance monitoring equipment) should be set forth within one standard. The SDT should add the maintenance and testing requirements as well. For utilities that may well have to invest considerable sums of money in the procurement and installation of new equipment, an awareness of any maintenance and testing requirements will allow for better informed, more cost effective procurement decisions
Response:		
Arizona Public Service Co.	Yes	
JEA	Yes	Protective relays based on microprocessor technology support SOE and DFR functionality, along with the ability to directly interface with local GPS satellite clocks for very accurate recording of events and faults. These SOE and DFR capabilities are programmed with the same software progams that "protection engineers" use to program settings and logic. The Protection System Maintenance and Test Project may be a better location to contain the maintenance requirements for SOE and DFR functionality provided by microprocessor protective relays. If Test and Maintenance requirements for the "same box" are developed independently of the PSMT Project, there is a distinct possibility of conflicting maintenance and test requirements for the "same box" and also the possbility of "double jeopardy" when it comes to VSLs and other auditable compliance criteria. DDR, PMU and legacy SOE, DFR and DDR maintenance and test requirements could be developed in alignment with other test and maintenance requirements through joint coordination between the DMSDT and PSTMSDT, or another SAR and new SAR team may need to be formed with team members from both a DM backgound and Protection Systems background to develop comprehensive maintenance and test requirement for DM equipment.
Response:		

Organization	Yes or No	Question 3 Comment
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Duke Energy	Yes	
CenterPoint Energy	Yes	
Xcel Energy	No	Even though there may be some overlap in hardware between DME and protection systems, we believe the maintenance requirement should be driven by the equipment function and impact on grid reliability. (Disturbance Monitoring Equipment should not be treated the same as protection system relays.) The PRC-002-2 SDT is in the best position to make that determination and specify maintenance requirements for DME.
Response:		
Utility System Efficiencies, Inc.	Yes	I agree with this proposal. However, I would suggest that current maintenance and testing requirements at either the NERC or RRO level be maintained until the new maintenance and testing standards are approved and in effect. In other words, don't eliminate any current requirements between now and the time new maintenance and testing requirements are put in place.In addition, testing requirements must, among other things, verify that the heterogenous sets of DDR data can be integrated and processed in a timely manner--e.g., the DDR types must in some sense be "interoperable." This will lead to desirable performance targets that should be incorporated into standards for future DDR installations. (See various documents on the WECC WAMS.)
Response:		
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	The current Reliability Standard PRC-005 for maintenance and testing of system protection systems may not be a good place for maintenance and testing of Disturbance Monitoring Equipment (DME). The maintenance and

Organization	Yes or No	Question 3 Comment
		testing requirements for DME are not the same as for system protection systems and for that reason it is not recommended to mix them with PRC-005 if that was being suggested by the SDT. Protective relaying may not operate between maintenance cycles, however, that is typically not the case for DME operation. Maintenance should not be required if a DME triggers and correctly captures a record on a regular basis. Do not disagree with the concept of of a separate standard for the maintenance and testing for DME.
Response:		
PNM	Yes	

4. The criteria used by the SDT in selecting locations for monitoring/recording Disturbance data is based on minimum number of elements (lines, transformers, etc.) or minimum amount of generation at a specific location. This approach facilitates the measurement of compliance to the requirements. Do you agree with the SDT's approach? Please provide specific comments, examples or recommendations.

Summary Consideration:

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	Yes	
IRC Standards Review Committee	Yes	The SRC would suggest that consideration be given to Market Entities that aggregate resources. It may be useful to specifically recognize "physical aggregation" so as to exclude "electronic aggregation."
Response:		
SPP System Protection and Control Working Group	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
Southern Company - Transmission	No	Southern Company supports the comments made by the SERC PCS. We urge the Drafting Team to utilize clarifying language in those areas identified in the comments of the SERC PCS. We are particularly keen on the idea of using diagrams to further clarify and illustrate the intent of the standard where needed. Southern Company disagrees with the use of arbitrary "checklist" values to determine location of disturbance monitoring equipment. As we commented in our response to Question #1, the determination of "where" to locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid in accordance with a NERC defined methodology.
Response:		

Organization	Yes or No	Question 4 Comment
SERC Engineering Committee Planning Standards Subcommittee	Yes	
SERC Protection and Controls Sub-committee	No	Agree with the approach given our understanding of thestandard's intent. The documents wording and Tables need to be clearerand more consistent. Suggest exempting 230 kV radial lines withouttransmission connected generation. Do not include these radial 230 KVlines in the count of 3 or more lines for SER & DFRs and do not includein the count of 7 or more lines for DDRs. It should be made clear thatthe equipment that must be monitored by a GO in Tables 2-1 and 5-1should be limited to equipment owned by the GO.Under Table 4.1, change the "and" below to "or." "Each Substation containing any combination of three (3) or more elements consisting of transmission lines operated at 200 kV or above and (change this "and" to "or") transformers having primary and secondary voltage ratings of 200 kV or above." Wording in Table 4.1 is more clear (assuming we understand the intent) than the wording in R1.1 and R1.2. We suggest that you use this clearer wording for these two requirements.We suggest that you make use of diagrams to make the intent clearer.
Response:		
PacifiCorp	No	While this approach does facilitate the measurement of compliance, it does not necessarily effectively target those elements that have the greatest impact to the reliability of the Bulk Electric System. The critieria used should also include consideration of factors reflecting the importance or significance of the location to the power grid. For example: Radial taps should not be included as part of the three element requirement (minimum number of elements).
Response:		
Dominion	Yes	We agree with the approach given our understanding of the standard's intent. The wording in the requirements and the tables need to be clearer and more consistent. It should be made clear that the equipment that must be monitored by the GO in tables 2-1 and 5-1 should be limited to equipment owned by the GO. We suggest replacing the word its with Generator Owner , and that the Heading of Table 2-1 be re-labeled to indicate: for generating plant and substation equipment owned by Generator OwnerAs an example: We ask for clarification of the intent of the term generator output breaker Please refer to the following example: A GO owns a breaker on the low-side of the GSU which is used to synchronize the unit. The TO owns breakers on the high-side of the GSU. For the purpose of this standard which of these breakers is deemed to be the generator output breaker(s)We suggest clarifying that any references to a low-side breaker to only include low-side breaker used as generator output breaker. We suggest exempting radial lines without transmission connected generation. Do

Organization	Yes or No	Question 4 Comment
		not include these radial lines in the count of 3 or more lines for SOE & FRs and do not include in the count of 7 or more lines for DDRs. Radial lines do not need to be monitored.
Response:		
Bonneville Power Administration	Yes	The element number criteria for SOE/FR/DDR needs to be adjusted (in general higher number criteria to not be burdensome to implement.). Also some stations that meet the proposed criteria are not as important, some that don't meet the criteria are. How many stations are impacted by SOE?
Response:		
FirstEnergy	Yes	
Florida Power & Light	Yes	Application of DMEs at the 200 kVand above is the correct voltage level to begin applying DMEs. However, substations with only three lines are approaching distribution size stations which would typically be served from larger stations that should be monitored. This would cause undue burdens on transmission owners. Although disturbances can begin at lower voltages they spread through the system at 200 kV and above. Moreover, any disturbance will always go back and be seen at the larger stations. Adequate data can be obtained at 200kV and above to determine system stability issues and frequency response.
Response:		
Los Angeles Department of Water & Power	No	Although we agree in principle with this criteria, establishing a substation voltage threshold at 200-kV creates specific problems for our utility. LADWP maintains a significant number of transmission lines and substations above 200-kV for supplying power around our large service area. Many of these stations are several buses away from interties with other utilities. We suggest that additional language be included in the proposed standards to exclude "internal-transmission lines" rated 200-kV and above from these regulations. Transmission lines and substations at or near intertie connections would still comply with proposed regulations. This proposed exclusion should have little to no impact on intertie data provided to NERC.
Response:		
MRO NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 4 Comment
PG&E System Protection	Yes	The Threshold for the number of elements is too low.
Response:		
US Bureau of Reclamation	No	"or minimum amount of generation at a specific location." Whatever is this, I do not agree to have one recorder for many generator units. Every generator should have an own DME (such as capabilities of SER and Wave-Capture by a micor-processor relay).
Response:		
NERC	Yes	As written, R1.1 would require SOERs only at stations that have 3 transmission lines AND transformers. I'm sure that was not the intent. For clarity, R1.1 should be reworded to read (consistent with Table 4.1): Contains any combination of five or more transmission lines elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above.?
Response:		
TransAlta	No	1. Selecting location for monitoring/recording disturbance data should be based on the disturbance analysis requirement as stated in the purpose section of this standard. But the SDT said," based on expected impact to the interconnected system. It is the team's strong belief that application of requirements below these values will require significant additional resources". This statement does not fully match the purpose.2. Using the minimum number of elements or minimum amount of generation at a specific location has two deficiencies. Firstly, it may exclude some locations where it is critical for BES reliable operation but not under this minimum number criterion. Secondly, it may waster the resource in the case which the disturbance data are collected in two adjacent locations defined in the draft standard where there are elements between each other. So it is recommended that SDT review the approach and satisfy the purpose of this standard. It is better to provide some guideline to select the location, instead of use the number. Another suggestion is that SDT look at FERC approved standard EOP-004-1 disturbance reporting to determine how to select the locations for monition/recording disturbance data to facilitate the analysis of the events specified in EOP-004-1.3. Disturbance data are mostly used by the entities that have a wide area view such as RC. Normally, these entities decide where to collect disturbance data for analysis. The draft standard does not have such wordings which allow these entities to have inputs to choose the locations and elements.
Response:		

Organization	Yes or No	Question 4 Comment
Grant County PUD	Yes	B.R1.1. I am unclear on this. The current language un-necessarily complicates things. I am concerned that the current wording could be interpreted to mean all locations with 3 T-Lines and any Xfmrs with any voltage greater than 200kv.I would suggest that the wording from the left hand column of Table 4-1 be used here. Table 4-1: Wording in first paragraph in left column of table is inconsistent with B.R1.1 when describing elements to count. Also, third bullet in right column is inconsistent with Xfmr description in left column.
Response:		
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	While we agree that using a minimum number of elements connected at some minimum voltage level is an appropriate method, we think that three elements may cause more substations to require the monitoring than is required to assure reliability.
Response:		
Cowlitz County PUD	Yes	I believe the applicability thresholds as described in the proposed standard goes a long way in bringing a reasonable dividing line between responsible reliability monitoring versus over extension of applicability just to make sure all the bases are covered. Smaller entities who can not possibly impact the BES in any way (cascading failure) will be spared unnecessary compliance expense.
Response:		
Portland General Electric	Yes	
Progress Energy Florida	Yes	
Puget Sound Energy		
Schneider Electric	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 4 Comment
American Electric Power	No	AEP believes that there is some misunderstandings of the term "Substation" as applied in the standard. The portion 'enclosed assemblage' is not clear enough to distinguish assets applicable to the standard. For example, distinct and separate busses, of differing voltage, that may be enclosed by a common fence. When Considered separately, one or the other separate busses may not meet requirement criteria, but considered combined, may meet criteria. When considered combined, AEP believes that the inclusion of additional facilities, simply because they are within the same fence, does not significantly enhance reliability as to be warranted.
Response:		
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid	No	Page 2, R1.1. of the mapping document as stated: R1.1. Contains any combination of three or more transmission lines operated at 200 kV or above and transformers having primary and secondary voltage ratings of 200 kV or above, contradicts: Page 4 Table 4-1 Each Substation containing any combination of three (3) or more elements consisting of transmission lines operated at 200 kV or above and transformers having primary and secondary voltage ratings of 200 kV or above. Further clarification is needed to avoid issues of interpretation.
Response:		
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	
DTE Energy/Detroit Edison		
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	I agree with the approach. This approach makes it clear where it is needed, except as noted below.

Organization	Yes or No	Question 4 Comment
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project	Yes	
Pacific Northwest National Laboratory	No	While it may be convenient to enforce, the location criteria seem overly simplistic. Some locations are more important than others; the RRO is usually aware of them, and should be given discretion to set their monitoring requirements. Please note that the WECC places special emphasis upon the monitoring of major control systems, especially those for HVDC terminals and FACTS-like devices [123]. I strongly doubt that substation measurements on the ac side of these devices is sufficient to determine their behavior.[123] WSCC Plan for Dynamic Performance and Disturbance Monitoring, prepared by the WECC Disturbance Monitoring Work Group, October 4, 2000.
Response:		
Progress Energy Carolina, Inc.	Yes	These requirements will create consistancy in the required locations where the regions "opinions" are not different.
Response:		
Hydro-Québec TransEnergie (HQT)	Yes	
Brazos Electric Power Cooperative, Inc.	No	The approach needs better engineering support of the criteria.
Response:		
WECC		

Organization	Yes or No	Question 4 Comment
Entergy Services, Inc	No	Simply specifying the number of elements may not be consistent with many existing Transmission Owner's historical DFR applicability criteria such as fault current availability and/or adjacent station coverage. A criteria consisting of a combination of the number of elements and a threshold short circuit MVA would be more appropriate for system coverage and yet still be measureable. Criteria should also include consideration for exceptions when there are adjacent station FRs in order to provide good system coverage and avoid unecessary redundant installations and expeditures. Also, the wording of R1.1 may does not seem be clear to everyone. Suggest the use of diagrams for clarity.
Response:		
Northeast Utilities		We agree that compliance must be measurable, and recognize also that it's possible for remote locations in a system to have a high concentration of generation spread across several busses. It would seem appropriate to require recorders in such areas. Also, in systems tightly networked at less than 200kV, it's possible for events to have significant impact on the EHV system, particularly under contingent conditions where EHV elements may be out of service.
Response:		
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
E.ON U.S.	No	The SDT approach would in some instances require installation of redundant data monitoring equipment. One DDR per substation should be adequate; not one per generating unit.
Response:		
Arizona Public Service Co.	Yes	
JEA	Yes	The choice of DFR data being derived from 200kV and above is a good selection from a continental standard perspective. The choice of 3 lines or greater provides for more coverage than is needed for DFRs. In some cases, 200kV 3 line substations will have very little impact on the overall bulk energy deleivery systems. In the cases where DDRs are located in close proximity to these 3 line 200 Kv stations, there should be allowances for

Organization	Yes or No	Question 4 Comment
		the fact that DDRs are covering the area and that DFRs may not be required from an additional data coverage standpoint.
Response:		
Tucson Electric Power	Yes	Comment - For an interconnection point that is a transformer with the high and low side voltages exceeding 200kV and two different utilities owning the high and low side of the transformer, do both parties need to install monitoring equipment as described or does one utility take the responsibility for installing the monitoring equipment on either the high or low side winding?
Response:		
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Duke Energy	No	We generally agree with the approach but refinements are needed. We suggest exempting 230 kV radial lines without transmission connected generation. Also do not include these radial 230 KV lines in the count of 3 or more lines for SER & DFRs and do not include in the count of 7 or more lines for DDRs.
Response:		
CenterPoint Energy	No	In Table 4.1 for Fault Recording Data, the SDT has attempted, to a degree, to allow monitoring of a substation at the remote terminals to preclude the requirement of installing Fault Recording equipment at the substation. For example, the first bullet indicates Fault Recording is required for each transmission line that does not have fault data recorded at its remote terminals?. In the second bullet, however, if the substation has a transmission bus, such as in breaker-and-a-half configurations, fault recording equipment is required. CenterPoint Energy's believes fault data recorded at remote terminals is sufficient for analyzing bus faults and autotransformer faults. Similar to the first bullet in Table 4.1, CenterPoint Energy recommends adding that does not have fault data recorded at its remote line terminals to the end of the second and third bullets that refer to buses and transformers.
Response:		

Organization	Yes or No	Question 4 Comment
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	While it may be convenient to enforce, the location criteria proposed can be overly simplistic. Some locations are more important than others; the RRO is usually aware of them, and should be given discretion to set their monitoring requirements. Please note that the WECC places special emphasis upon the monitoring of major control systems, especially those for HVDC terminals and FACTS-like devices. Substation measurements on the ac side of these devices may not be sufficient to adequately determine their behavior.
Response:		
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	No	The defining sum of lines and transformers should be 4 instead of 3. The sum of 3 will exclude few sites.
Response:		

5. In developing the Disturbance data requirements the SDT decided to focus on transmission voltage levels of 200 kV and above, generators 500 MVA and above, and generating stations 1500 MVA and above based on expected impact to the interconnected system. It is the team's strong belief that application of requirements below these values to include the entire BES will require significant additional resources, while adding little value.

The proposed standard requires the following:

The status of GSU circuit breakers for generating plants connected at 200 kV and above shall be monitored on each generator with a nameplate capacity of 500 MVA or higher or an aggregate plant total of 1500 MVA or higher.

5.1 Do you agree with these nameplate values? Please provide supporting documentation for these values. If not, please propose alternate values and their technical basis.

Summary Consideration:

Organization	Yes or No	Question 5.1 Comment
Northeast Power Coordinating Council	No	Performance based stability studies have identified facilities operated at voltages below 200kV, generators with less than 500MVA capacity, aggregate plants with less than 1500MVA that when lost would have a significant impact on the power system. Monitoring should not be limited to breaker positions--this will improve event analysis. We do not feel that the 200kV threshold is an appropriate criteria for assessing criticality.
Response:		
IRC Standards Review Committee	Yes	As in the response to #4, the SRC would suggest that consideration be given to Market Entities that aggregate resources. It may be useful to specifically recognize "physical aggregation" so as to exclude "electronic aggregation."
Response:		
SPP System Protection and Control Working Group	Yes	Recommend to include GSU circuit breakers for generating plants connected at critical substations below 200kV. Recent disturbances in the SPP area have shown the need to include GSU circuit breakers for generating plants connected at less than 200kV.

Organization	Yes or No	Question 5.1 Comment
Response:		
Members of the WECC Disturbance Monitoring Work Group	Yes	We agree with the nameplate values. However, we have two questions. 1) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators 2) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV Is this standard applicable to this plant?
Response:		
Southern Company - Transmission	Yes	No further comment.
SERC Engineering Committee Planning Standards Subcommittee	Yes	These values seem to be in the appropriate range.
Response:		
SERC Protection and Controls Sub-committee	Yes	
PacifiCorp	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	For generating stations with split interconnection voltages (some units connected below 200 kV), define how to interpret.
Response:		
FirstEnergy	Yes	Our "yes" response is based on the fact that we have no strong technical reason to deviate from the values proposed by the SDT. In review of our own FirstEnergy footprint, the proposed values seem to capture the generation facilities that would most likely have a BES reliability impact. However, we would like to better understand the technical

Organization	Yes or No	Question 5.1 Comment
		rationale used by the SDT in choosing these values.
Response:		
Florida Power & Light	Yes	
Los Angeles Department of Water & Power	Yes	These values appear reasonable and affect several of our generating stations.
Response:		
MRO NERC Standards Review Subcommittee	Yes	While the MRO NSRS does not disagree with the levels mentioned above, what is the technical basis for selecting those levels?
Response:		
PG&E System Protection	Yes	We agree with the nameplate values. However, we have two questions. 1) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators 2) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV Is this standard applicable to this plant?
Response:		
US Bureau of Reclamation	No	These capacites (500MVA/unit and 1500MVA/plant) are too large. This will not help over-all post-disturbacne analysis. These values should be 20MVA/unit and 75MVA/plant.
Response:		
NERC	No	Disagree with 200 kv and above...should be 100 kv and above.
Response:		
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification

Organization	Yes or No	Question 5.1 Comment
Response:		
Grant County PUD	Yes	
NYISO	No	We agree with these threshholds for some application of DME's, however for SOE requirements, we believe it should be reduced to 50MVA unit and 300MVA plant. Loss of generation affects the entire interconnection regardless of voltage level, and these levels are based on NPCC's current criteria. During a system wide event, many small generators may trip, and this generation adds up and is the reasoning behind monitoring smaller levels.
Response:		
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	For the WECC area, if we can't withstand a 1500 MVA loss without a cascading failure, then the system is operating too close to the line. I think the burden of proof should be on those who would argue for more stringent nameplate values.
Response:		
Portland General Electric	Yes	The following are the comments of the DMWG which we are filing in support: We agree with the nameplate values. However, we have two questions. 1) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators? 2) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
Progress Energy Florida	Yes	
Puget Sound Energy	Yes	We agree with the nameplate values. However, we have two questions. 1) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators? 2) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this

Organization	Yes or No	Question 5.1 Comment
		standard applicable to this plant?
Response:		
Schneider Electric		
Independent Electricity System Operator	Yes	
American Electric Power	Yes	To provide better clarity of the requirement, it should be worded: The status of GSU circuit breakers for generating plants connected at 200 kV and above shall be monitored on each generator with a nameplate capacity of 500 MVA or higher, OR an aggregate plant total of 1500 MVA or higher AND CONNECTED AT 200kV AND ABOVE. AEP agrees with these nameplate values. If criteria goes to 100 kv, then a much longer implementation period will be needed for the enormous amount of work that may be required. For AEP, 100 kv equipment is not for transport of bulk power and is generally considered a distribution system. Since the goal of NERC is to have a more reliable system, the outages will invariably weaken the system for a period of time while companies are installing required equipment does not support this goal. For stressed systems, outages may be difficult to even get, especially those areas west of the Mississippi that have weak systems to begin with. Enhanced analysis data does nothing to directly improve the reliability of the system, but provides data for analyzing events after they have already happened. Granted, it may uncover misoperations that can be mitigated so that they do not happen again, but there is already a standard for that.
Response:		
NextEra Energy Resources (formerly FPL Energy)	No	In light of the same argument made above, it is recommended that the single generating unit level be changed to "750MVA or higher".
Response:		
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	No	Comments on PRC-002-2---Disturbance Monitoring and Reporting Requirements Draft 1, January 30, 2009 1. Requirements R2 and R3: Please clarify in this section that Generator Owner (GO) shall record the Sequence of

Organization	Yes or No	Question 5.1 Comment
		Events data for changes in circuit breaker position only if GO owns the circuit breakers. If Transmission Owner (TO) owns the output circuit breaker, then recording the Sequence of Events data for the Generator output circuit breaker position, is the responsibility of the TO and not of GO.
NV Energy	Yes	
DTE Energy/Detroit Edison	No	"Aggregate plant total of 1500 MVA or higher" implies that several small generators, or peaking units, would have to be individually monitored if the total is 1500 MVA or higher. Suggest that 500 MVA be used as minimum generator size to be monitored.
Response:		
Wisconsin Electric	No	We agree with these nameplate values for Sequence of Event data and Fault Recording data. However, the requirement for Dynamic Disturbance Recording data should have a higher threshold since it is a higher level monitoring equipment, looking at power swings instead of just fault data. We suggest that an aggregate nameplate rating of 2000 MVA is more reasonable. See #11 below.
Response:		
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	However, some confusion may be encountered when determining if it is a "plant" or "site" aggregate. Some utilities may not use the same nomenclature for each item. Two 900MW plants (or units) at one site should be captured, even though they are not a plant aggregate of 1500MVA.
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	These MVA and voltage levels appear to be appropriate for the intent of this Standard.

Organization	Yes or No	Question 5.1 Comment
Response:		
Salt River Project	Yes	
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	No	Performance based stability studies have identified facilities operated at voltages below 200kV, generators with less than 500MVA capacity, aggregate plants with less than 1500MVA that when lost would have a significant impact on the power system. Monitoring should not be limited to breaker positions--this will improve event analysis. We do not feel that the 200kV threshold is an appropriate criteria for assessing criticality whether as a lower limit or a higher one; in some system, not all 200 kV facilities and above are critical. A performance based stability studies can be used to determine the appropriate system that should be monitored.
Response:		
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	No	See comments for question #4. Also, monitoring should not be limited to breaker positions; knowledge regarding what caused a generator to trip will improve event analysis.
Response:		
San Diego Gas and Electric Co.	Yes	

Organization	Yes or No	Question 5.1 Comment
New York Independent System Operator	No	Loss of generation affects the system regardless of the voltage level the generator is connected. For Sequence of Events requirements, change units size to 50MVA, plant size to 300MVA, remove reference to connected at 200kV+ Change references to these levels for all Generator SOE requirements. See NERC 2003 Blackout Technical Report Recommendation TR-9
Response:		
E.ON U.S.	No	E ON US recommends use of an aggregate nameplate value for generating plants of 2000 MVA or higher, as recommended in Standard EOP-004 Disturbance Reporting.
Response:		
Arizona Public Service Co.	Yes	There needs to be some consideration for generator owners who don't own/operate the switchyard that the generator circuit breaker is in as they may not have ready access to the breaker status for high speed recording and they may be beholden to the switchyard owner to get access. Also, a power plant with an aggregate of 1500 MVA or higher might only have a small portion of the generation connected at 200 kV and above. Those portions not connected to the 200 kV and above system should not be required to meet the standard.
Response:		
JEA	Yes	
Tucson Electric Power	Yes	We agree with the nameplate values. However, we have two questions. 1) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators? 2) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
Alberta Electric System Operator	Yes	
Beckwith Electric Co	No	Recommend changing it to: "The status of GSU circuit breakers and sequence of events data of protective relay

Organization	Yes or No	Question 5.1 Comment
		operations at the generating plants with a name plate capacity of 50 MVA or higher or an aggregate plant total of 300 MVA or higher. "This will help possible future blackout investigations and improve generator - transmission system protection coordination for plants of significant size. This requirement should be based on the plant size and not the connected transmission voltage.
Response:		
Duke Energy	Yes	
CenterPoint Energy		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	I agree with the nameplate values. However, I have two questions. 1) R2 and table 2.1. requires the GO to record or have a process in place to derive the Sequence of Events data for changes in circuit breaker position for its equipment. What if the GO does not own the circuit breakers for their Generators? 2) What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	

5.2 In part, Requirement R5 states that Fault Recording data shall be recorded at generating plants connected at 200 kV and above when a generator has a nameplate capacity of 500 MVA or higher or when there is an aggregate plant total of 1500 MVA or higher. Do you agree with these values? Please provide supporting documentation for these values. If not, please propose alternate values and their technical basis.

Summary Consideration:

Organization	Yes or No	Question 5.2 Comment
Northeast Power Coordinating Council	Yes	
IRC Standards Review Committee	Yes	As in the response to #4, the SRC would suggest that consideration be given to Market Entities that aggregate resources. It may be useful to specifically recognize "physical aggregation" so as to exclude "electronic aggregation."
Response:		
SPP System Protection and Control Working Group	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
Southern Company - Transmission	Yes	No further comment.
Response:		
SERC Engineering Committee Planning Standards Subcommittee	Yes	These values seem to be in the appropriate range.

Organization	Yes or No	Question 5.2 Comment
Response:		
SERC Protection and Controls Sub-committee	Yes	
PacifiCorp	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	For generating stations with split interconnection voltages (some units connected below 200 kV), define how to interpret.
Response:		
FirstEnergy	Yes	Our "yes" response is based on the fact that we have no strong technical reason to deviate from the values proposed by the SDT. In review of our own FirstEnergy footprint, the proposed values seem to capture the generation facilities that would most likely have a BES reliability impact. However, we would like to better understand the technical rationale used by the SDT in choosing these values.
Response:		
Florida Power & Light	Yes	
Los Angeles Department of Water & Power	Yes	These values appear reasonable and affect several of our generating stations.
Response:		
MRO NERC Standards Review Subcommittee	Yes	Why do the TOP with Frequency Recorders need to record Voltage line to neutral (R4 or R5.4) but the GO can read Voltage line neutral or Voltage line to line. (R5)?
Response:		
PG&E System Protection	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at

Organization	Yes or No	Question 5.2 Comment
		greater than 200 kV? Is this standard applicable to this plant?
Response:		
US Bureau of Reclamation	No	These capacites (500MVA/unit and 1500MVA/plant) are too large. This will not help over-all post-disturbacne analysis. These values should be 20MVA/unit and 75MVA/plant.
Response:		
NERC	No	Disagree with 200 kv and above...should be 100 kv and above. It is important for forensic analysis to have both bus and line quantities for DFR quantities. Bullets 2 and 3 should read: On breaker-and-a-half arrangements, the outer bus voltages, and the individual line voltages.On straight buses, common bus voltages and the individual line voltages.
Response:		
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
Response:		
Grant County PUD		
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	Again, I feel the burden of proof should be on those who would argue for more stringent criteria.
Response:		
Portland General Electric	Yes	The following are the comments of the DMWG which we are filing in support: What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?

Organization	Yes or No	Question 5.2 Comment
Response:		
Progress Energy Florida	Yes	
Puget Sound Energy	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
Schneider Electric		
Independent Electricity System Operator	Yes	
American Electric Power	Yes	AEP agrees with these values. If criteria goes to 100 kv, then a much longer implementation period will be needed for the enormous amount of work that may be required. For AEP, 100 kv equipment is not for transport of bulk power and is generally considered a distribution system. Since the goal of NERC is to have a more reliable system, the outages that will invariably weaken the system for a period of time while companies are installing required equipment does not support this goal. For stressed systems, outages may be difficult to even get, especially those areas west of the Mississippi that have weak systems to begin with. Enhanced analysis data does nothing to directly improve the reliability of the system, but provides data for analyzing events after they have already happened. Granted, it may uncover misoperations that can be mitigated so that they do not happen again, but there is already a standard for that.
Response:		
NextEra Energy Resources (formerly FPL Energy)	No	In light of the same argument made above, it is recommended that the single generating unit level be changed to "750MVA or higher".
Response:		
National Grid		
Manitoba Hydro	Yes	

Organization	Yes or No	Question 5.2 Comment
Exelon Generation LLC	Yes	
NV Energy	Yes	
DTE Energy/Detroit Edison	No	Please see comment for 5.1.
Response:		
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	This looks like the same as question 5.1. Are you asking if I agree with the 200kV threshold? If so, I agree, but I do not see the need to record the low side breakers per Table 2-1.
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	These MVA and voltage levels appear to be appropriate for the intent of this Standard.
Response:		
Salt River Project	Yes	
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	No	See Q5.1 answer above.

Organization	Yes or No	Question 5.2 Comment
Response:		
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
E.ON U.S.	No	E ON US recommends use of an aggregate nameplate value for generating plants of 2000 MVA or higher, as recommended in Standard EOP-004 Disturbance Reporting.
Response:		
Arizona Public Service Co.	No	This should only be required for new plants that meet the criteria defined. Existing plants should be grandfathered. The other issues mentioned in Question 5.1 comments should also be considered and they are copied here: There needs to be some consideration for generator owners who don't own/operate the switchyard that the generator circuit breaker is in as they may not have ready access to the breaker status for high speed recording and they may be beholden to the switchyard owner to get access. Also, a power plant with an aggregate of 1500 MVA or higher might only have a small portion of the generation connected at 200 kV and above. Those portions not connected to the 200 kV and above system should not be required to meet the standard.
Response:		
JEA	Yes	

Organization	Yes or No	Question 5.2 Comment
Tucson Electric Power	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
Alberta Electric System Operator	Yes	
Beckwith Electric Co	No	Recommend changing to: "Fault Recording data shall be recorded at generating plants when a generator has a nameplate capacity of 50 MVA or higher or when there is an aggregate plant total of 300 MVA or higher. "This will help possible future blackout investigations and improve generator - transmission system protection coordination for plants of significant size. This requirement should be based on the plant size and not the connected transmission voltage.
Response:		
Duke Energy	Yes	
CenterPoint Energy		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	

5.3 Requirement R7 states that DDR data shall be recorded or derivable for all substations having a total of seven or more transmission lines connected at 200 kV or above. Do you agree with these values? Please provide supporting documentation for these values. If not, please propose alternate values and their technical basis.

Summary Consideration:

Organization	Yes or No	Question 5.3 Comment
Northeast Power Coordinating Council	Yes	
IRC Standards Review Committee	Yes	The SRC agrees with the SDT decision to specify a common limit and recognize that special cases not covered by the common limit will be addressed by regional standards.
Response:		
SPP System Protection and Control Working Group	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
Southern Company - Transmission	No	Southern Company disagrees with the use of arbitrary "checklist" values for placement of DDR equipment. As we commented in our response to Questions #1 and #4, the determination of "where" to locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid in accordance with a NERC defined methodology.
Response:		
SERC Engineering Committee Planning Standards	Yes	These values seem to be in the appropriate range.

Organization	Yes or No	Question 5.3 Comment
Subcommittee		
SERC Protection and Controls Sub-committee	No	Seven lines seems to be an arbitrary number (would not cover potentially needed locations and would require installations at locations not critical to the system). We suggest wording similar to that used in the SERC DME supplement. The required siting of DDR should be coordinated through the efforts of the appropriate reliability assessment groups that may be involved in accordance with the guidance provided in PRC-002- 2. These locations are selected to provide extended time power system monitoring capability in order to assist analyses wide area disturbances. These locations are chosen to provide coverage across the BES EHV network. The locations selected should include the following considerations: Major load centers Major generation clusters Major voltage sensitive area Major transmission interfaces Major transmission junctions Elements associated with Interconnection Reliability Operating Limits Major EHV interconnections between control areas
Response:		
PacifiCorp	Yes	
Dominion	No	Radial lines without transmission connected generation should not be included in the element count. Radial line feeding only load doesn't provide significant contribution to grid disturbances. Also we suggest rewarding R7 to: Each Substation having a total of seven or more transmission lines (not including radial Lines) connected at 200 kV or above, the Transmission Owner shall record (or have a process in place to derive) the following DDR data unless a Transmission Owner has Dynamic Disturbance Recording (DDR) data meeting all of the requirements of R7.1, R7.2, R7.3, and R7.4 recorded no further than two Substations away.
Response:		
Bonneville Power Administration	Yes	With coverage by FR and SOE, BPA does not think that DDR's are necessarily required at the same location. Their purpose is for overview devices and not as many may be required.
Response:		
FirstEnergy	Yes	
Florida Power & Light	Yes	We generally agree with this, however, it needs some defining.

Organization	Yes or No	Question 5.3 Comment
Response:		
Los Angeles Department of Water & Power	No	As stated earlier, LADWP distributes power around our service area at 230-kV. As a result, several of our transmission lines and substations fall within these proposed regulations yet have little influence on interties with other utilities. Additional language to exclude "internal transmission" resources from these regulations should be considered.
Response:		
MRO NERC Standards Review Subcommittee	Yes	
PG&E System Protection	Yes	
US Bureau of Reclamation	Yes	
NERC	No	For consistency in description, the DDR requirement in R7 should mirror the station description in R1.1: “then for each Substation having any combination of seven or more transmission elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above a, the Transmission Owner shall record..."
Response:		
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
Response:		
Grant County PUD	No	R7 is very difficult to read. A reword similar to is suggested: When a Transmission owner DOES NOT have Dynamic Disturbance Recording (DDR) data meeting all of the requirements of R7.1, R7.2, R7.3, and R7.4, recorded no further than 2 Substations away, then.....
Response:		

Organization	Yes or No	Question 5.3 Comment
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	Again, I feel the burden of proof should be on those who would argue for more stringent criteria.
Response:		
Portland General Electric	Yes	
Progress Energy Florida	Yes	
Puget Sound Energy	Yes	
Schneider Electric		
Independent Electricity System Operator	No	In some areas of the interconnected network, there are substations that have fewer than 7 lines (typically 4 to 6 lines) connected to them. These areas might be sparsely populated but through them, transmission facilities are installed to facilitate transfer of remote resource to the load centres while supplying local area loads. Not having fault/disturbance recorders installed at these substations may create a void in the necessary data for event analysis. We suggest the SDT consider lowering the number to 4.
Response:		
American Electric Power	Yes	AEP agrees with these values. If criteria goes to 100 kv, then a much longer implementation period will be needed for the enormous amount of work that may be required. For AEP, 100 kv equipment is not for transport of bulk power and is generally considered a distribution system. Since the goal of NERC is to have a more reliable system, the outages that will invariably weaken the system for a period of time while companies are installing required equipment does not support this goal. For stressed systems, outages may be difficult to even get, especially those areas west of the Mississippi that have weak systems to begin with. Enhanced analysis data does nothing to directly improve the reliability of the system, but

Organization	Yes or No	Question 5.3 Comment
		provides data for analyzing events after they have already happened. Granted, it may uncover misoperations that can be mitigated so that they do not happen again, but there is already a standard for that.
Response:		
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	
DTE Energy/Detroit Edison		
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	

Organization	Yes or No	Question 5.3 Comment
Salt River Project	Yes	
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	No	Seven lines seems to be an arbitrary number (would not cover potentially needed locations and would require installations at locations not critical to the system). We suggest wording similar to that used in the SERC DME supplement. The required siting of DDR should be coordinated through the efforts of the appropriate reliability assessment groups that may be involved in accordance with the guidance provided in PRC-002- 2. These locations are selected to provide extended time power system monitoring capability in order to assist analyses wide area disturbances. These locations are chosen to provide coverage across the BES EHV network. The locations selected should include the following considerations: Major load centers Major generation clusters Major voltage sensitive areas Major transmission interfaces Major transmission junctions Elements associated with Interconnection Reliability Operating Limits Major EHV interconnections between control areas
Response:		
Hydro-Québec TransEnergie (HQT)	No	See Q5.1 answer above.
Response:		
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	No	The number of lines criteria is too arbitrary and will require an excessive number of installations at some entities and perhaps none at others. A better criteria is one that aligns with Regional needs and distributes these type of installations more evenly throughout the Region. Have the Regional Planning groups review and address where DDRs would be most effective and actually needed.
Response:		

Organization	Yes or No	Question 5.3 Comment
Northeast Utilities		We agree that compliance must be measurable, and recognize also that it's possible for remote locations in a system to have a high concentration of generation spread across several busses. It would seem appropriate to require recorders in such areas.
Response:		
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
E.ON U.S.		
Arizona Public Service Co.	No	While the general premise might be acceptable, the Requirement R7 requires the DDR to monitor one phase current from every line operated 200 kV and above. This might not be possible or may be extremely difficult for some cases especially where the substation is jointly own/operated, is extremely large, or is quite old. The requirement should state a percentage of lines that must be monitored (say 50%).
Response:		
JEA	Yes	There is good correlation from multiple regions in support of the 200kV level and above for the busses that are considered the "most impactful" when considering major disturbances within a region. Busses that have a 10,000 MVA and above three phase short circuit capacity are significantly represented by 200kV and above criteria. When reviewing regional data for the 10,000 MVA and above three phase short circuit capacity, over 90% of those busses that are connected to generation, meet the 500/1500 MVA selected levels for generation, in support of the team's choice of these levels.
Response:		
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	

Organization	Yes or No	Question 5.3 Comment
Beckwith Electric Co	Yes	
Duke Energy	No	Seven lines seems to be an arbitrary number (would not cover potentially needed locations and would require installations at locations not critical to the system). We suggest wording similar to that used in the SERC DME supplement. The required siting of DDR should be coordinated through the efforts of the appropriate reliability assessment groups that may be involved in accordance with the guidance provided in PRC-002-2. These locations are selected to provide extended time power system monitoring capability in order to assist analyses of wide area disturbances. These locations are chosen to provide coverage across the BES EHV network. The locations selected should include the following considerations: Major load centers Major generation clusters? Major voltage sensitive areas Major transmission interfaces Major transmission junctions Elements associated with Interconnection Reliability Operating Limits Major EHV interconnections between control areas
Response:		
CenterPoint Energy	No	CenterPoint Energy disagrees that criteria for Dynamic Disturbance Recording (DDR) should be solely based upon the number of connected lines at a substation. In addition to the number of lines, CenterPoint Energy recommends that DDR equipment be required only in substations that have direct interconnections to generating units.
Response:		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	

Requirements related to Sequence of Events

6. Requirement R3 states that Transmission Owners and Generator Owners shall record the time stamp or have a process in place to derive the time stamp to within four milliseconds of input received for the change in circuit breaker position (open/close) Do you agree with this value? If no, propose an alternate value and please provide technical basis.

Summary Consideration:

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	Yes	
IRC Standards Review Committee	Yes	The SRC would suggest that Requirement 3 be separated into two independent requirements - one for TOs and one for GOs. Although the intent is to combine the two parallel requirements, it is possible for a compliance person to interpret the "AND" as an "inclusive AND" and require the TO (or GO) to have data for both R1 and R2 criteria.
Response:		
SPP System Protection and Control Working Group	No	Please clarify and give examples of the "four milliseconds of input received" and "have a process in place to derive". What is the basis for choosing "four milliseconds" over "quarter cycle"? Please ensure that using relays for this requirement is sufficient.
Response:		
Members of the WECC Disturbance Monitoring Work Group	Yes	
Southern Company - Transmission	Yes	Southern Company suggests the Drafting Team use their "reponses to comments" period to enlighten industry as to how a 4msec value was chosen for Requirement #4 and how a +/- 2msec value was chosen for Requirement #12.
Response:		

Organization	Yes or No	Question 6 Comment
SERC Engineering Committee Planning Standards Subcommittee	Yes	
SERC Protection and Controls Sub-committee	Yes	Suggest in R3, for consistency, use similar terminology to R12 (where reference is +/- 2 ms).
Response:		
PacifiCorp	Yes	
Dominion	Yes	
Bonneville Power Administration	No	BPA believes 2-4 second SCADA/EMS records are good enough for most events.
Response:		
FirstEnergy	No	To allow for some flexibility and consistent with other requirements, we recommend replacing 4 ms with 1/4 cycle.
Response:		
Florida Power & Light	Yes	However, please view our comments for question 17.
Response:		
Los Angeles Department of Water & Power		
MRO NERC Standards Review Subcommittee	Yes	
PG&E System Protection	Yes	
US Bureau of Reclamation	Yes	

Organization	Yes or No	Question 6 Comment
NERC	Yes	
TransAlta		
Grant County PUD	Yes	
NYISO	Yes	
Tri-State Generation and Transmission Association	No	This wording seems very confusing. Does it intend to require that the time stamp will be recorded to indicate the time of the change in state of the breaker with an accuracy of +/- 4 milliseconds 2 millisecond resolution is required in R12. Is this inconsistent with that Requirement?
Response:		
Cowlitz County PUD	Yes	
Portland General Electric	Yes	
Progress Energy Florida	Yes	
Puget Sound Energy		
Schneider Electric		
Independent Electricity System Operator	No	The disturbance monitoring function to which this time stamp refers is not obvious. From the flow of the requirements it appears to relate to sequence of events recording. If the requirement is indeed for the sequence of event recorder to mark a change in the status within 4 milliseconds of receiving an input of a change in the circuit breaker position, then the requirement should clearly state it is for the SOE recorder as otherwise, it will serve no purpose if the requirement is interpreted as applicable for a fault recording device. Further, please elaborate on the basis for the 4 ms.
Response:		
American Electric Power	Yes	

Organization	Yes or No	Question 6 Comment
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	No	Comments on PRC-002-2---Disturbance Monitoring and Reporting Requirements Draft 1, January 30, 2009 1. Requirements R2 and R3: Please clarify in this section that Generator Owner (GO) shall record the Sequence of Events data for changes in circuit breaker position only if GO owns the circuit breakers. If Transmission Owner (TO) owns the output circuit breaker, then recording the Sequence of Events data for the Generator output circuit breaker position, is the responsibility of the TO and not of GO.
Response:		
NV Energy	Yes	
DTE Energy/Detroit Edison		
Wisconsin Electric		
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	
PHI (PEPCO Holdings Inc.)	No	The time should be listed as 1/4 cycle, since many relays specs indiacte 1/4 cycle for this requirement.
Response:		
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 6 Comment
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
E.ON U.S.		In answering this question, E ON US would benefit from knowing the SDT's technical basis for the 4 milliseconds
Response:		
Arizona Public Service Co.	Yes	This is not consistent with requirement R12 which states +/- 2 ms since within 4 ms means +/- 4.
Response:		
JEA	Yes	ocal GPS satellite clocks are needed to properly time tag events and provide for correct data for analysis purposes. It should be noted that breaker mechanical contacts, "a" "b" "aa" and "bb", can be significantly outside of the range of 4 milliseconds in tolerance for certain types of breakers. A method to accommodate values outside the 4 millisecond range may need to be accomodated.
Response:		

Organization	Yes or No	Question 6 Comment
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	The AESO supports the IRC SRC comments to this question.
Response:		
Beckwith Electric Co	Yes	
Duke Energy	Yes	Suggest in R3, for consistency, use similar terminology to R 12 (where reference is +/- 2 ms).
Response:		
CenterPoint Energy		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	No	Many protective relays sample inputs every quarter cycle, equivalent to 4.2 msec. Is the 4 msec requirement above intended to disqualify relays from being used as recording devices for breaker position? What is meant by a process in place to derive time stamp? Can examples be provided?
Response:		
PNM	Yes	

Requirements related to Sequence of Events

7. Do you agree with the other Sequence of Events requirements under R1 through R3 of the proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Summary Consideration:

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	Sequence of Events requirements should include monitoring of transmission and generator circuit breaker positions, protective relay tripping for all protection groups, and teleprotection keying and receiving.
Response:		
IRC Standards Review Committee	No	The SRC agrees with the main requirement R1.However, the SRC does not agree with making R1.1 and R1.2 independent requirements. These two inclusions are explanatory text not specific ad hoc requirements. Note that in R2 the explanatory text is included in a Table not as independent requirements.
Response:		
SPP System Protection and Control Working Group	Yes	
Members of the WECC Disturbance Monitoring Work Group	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Response:		
Southern Company - Transmission	No	Southern Company disagrees with the use of arbitrary "checklist" values. As we commented in our response to Questions #1, #4 and #5.3, the determination of "where" to locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid in accordance with a NERC defined methodology.
Response:		

Organization	Yes or No	Question 7 Comment
SERC Engineering Committee Planning Standards Subcommittee	Yes	
SERC Protection and Controls Sub-committee	No	Reference comments on #4 above. Suggest in R3, for consistency, use similar terminology to R12 (where reference is +/- 2 ms).
Response:		
PacifiCorp	No	Three or more lines connected to a substation does not clearly indicate impact or significance to the bulk electric system. Also see comment 4. above.
Response:		
Dominion	Yes	The location requirements for SOEs and FRs for TO should be the same. If we use a table under R4 then use a similar table under R1- R2 remove its and replace with Generator Owner , and re-label Heading of Table 2-1 to indicate: for generating plant and substation equipment owned by Generator Owner? Table 2-1 - remove the third and fourth row of info. Move the "each circuit breaker 200 KV and above" in the right hand column of rows 3 and 4 to right hand column of rows 1 and 2.
Response:		
Bonneville Power Administration	No	With relay based SOE/FR capability plus standalone, BPA believes 2-4 second SCADA/EMS records are good enough for most events. The number of element criteria may be too stringent, change to 5 elements.
Response:		
FirstEnergy	Yes	
Florida Power & Light	Yes	
Los Angeles Department of Water & Power		
MRO NERC Standards Review	Yes	

Organization	Yes or No	Question 7 Comment
Subcommittee		
PG&E System Protection	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirment be for substations with five or more lines operated at 200 kV or above.
Response:		
US Bureau of Reclamation	Yes	
NERC	No	R1.1As written, R1.1 would require SOERs only at stations that have 3 transmission lines AND transformers. I'm sure that was not the intent. For clarity, R1.1 should be reworded to read (consistent with Table 4.1):Contains any combination of five or more transmission lines elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above. Note the change from 3 elements to 5 elements...3 elements would require a significant number of new installations.
Response:		
TransAlta		
Grant County PUD	Yes	
NYISO	No	For SOE requirements, we believe it should be reduced to 50MVA unit and 300MVA plant. Loss of generation affects the entire interconnection regardless of voltage level, and these levels are based on NPCC's current criteria. During a system wide event, many small generators may trip, and this generation adds up and is the reasoning behind monitoring smaller levels. Just monitoring breaker position isn't enough. The SOE should monitor CB position, protective relaying tripping of all protection groups, and teleprotection keying and receive. The 3rd and 4th row in the table puts the responsibility to monitor the transmission substation on the generation owner. This should be changed such that the station owner is required to monitor SOE at the substation. For monitoring the transmission substation SOE, we believe the 500MVA unit / 1500MVA plant, 200kV+ interconnection threshold is adequate.
Response:		

Organization	Yes or No	Question 7 Comment
Tri-State Generation and Transmission Association	Yes	We would like to ensure that no separate Sequence of Events Recorder is required if the data can retrieved from archived SCADA logs.
Response:		
Cowlitz County PUD	Yes	
Portland General Electric	No	The following are the comments filed by the DMWG which we are filing in support: The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Response:		
Progress Energy Florida	No	Table 2-1 indicates "Including low side breakers" for plant SER data inputs. If an aggregate generation site of 1500MVA is monitored at the >200kV level where the generation enters the transmission network, the system impact of any occurrence will be seen at the monitoring point. PEF disagrees with the low side breakers position being included to be monitored by the DFR/SER. Monitoring of these breakers are included within the functional boundaries of the smaller generating units and the breaker voltages are less than 50KV and not part of the transmission grid. Extending this requirement will be costly since the DFR will be located at the transmission network location remote to the multiple generators and low side breakers. The requirement should only include the >200kV circuit breaker SER data.
Response:		
Puget Sound Energy	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Response:		
Schneider Electric	Yes	

Organization	Yes or No	Question 7 Comment
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	No	Comments on PRC-002-2---Disturbance Monitoring and Reporting Requirements Draft 1, January 30, 2009 1. Requirements R2 and R3: Please clarify in this section that Generator Owner (GO) shall record the Sequence of Events data for changes in circuit breaker position only if GO owns the circuit breakers. If Transmission Owner (TO) owns the output circuit breaker, then recording the Sequence of Events data for the Generator output circuit breaker position, is the responsibility of the TO and not of GO.
Response:		
NV Energy	Yes	
DTE Energy/Detroit Edison	No	Recommend that generator low side breaker monitoring should be excluded or optional if the high side breaker connected to the system is monitored.
Response:		
Wisconsin Electric	No	In R2, the Generator Owner is required to record Sequence of Events (SER) data for circuit breaker status for the equipment in the substation connected to a generating station of a specified capacity, in addition to that for the GSU. This appears to be an unnecessary duplication of equipment already being monitored by the Transmission Owner in R1. If this is a correct interpretation, we believe this requirement is redundant, and technically and financially unjustified. We strongly oppose requiring duplication of monitoring equipment for the same facility by both Transmission Owners and Generator Owners.
Response:		

Organization	Yes or No	Question 7 Comment
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	No	R1.1 is unclear. Is it the intent of the SDT to exclude substations with 3 or more lines at 200kV or above if there is no transformation at that substation? That appears to be what is required based on the "and" statement.R1.2: Some confusion may be encountered when determining if it is a "plant" or "site" aggregate. Some utilities may not use the same nomenclature for each item. Two 900MW plants (or units) at one site should be captured, even though they are not a plant aggregate of 1500MVA.
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	No	The requirement to provide Sequence of Events recording data for stations with three or more transmission lines operated at 200kV or above seems to be overly burdensome. This requirement if left as written would potentially include a significant number of remote substations. As an alternative, we suggest that this requirement be changed to "stations with five or more lines operated at 200kV or above".
Response:		
Salt River Project	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. Suggest that this requirment be for substations with five or more lines operated at 200 kV or above.
Response:		
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	No	Table 2-1 indicates "Including low side breakers" for plant SER data inputs. If an aggregate generation site of 1500MVA is monitored at the >200kV level where the generation enters the transmission network, the system impact of any occurrence will be seen at the monitoring point. PEC dissagrees with the low side breakers position being included to be monitored by the DFR/SER. Monitoring of these breakers are included within the functional boundaries of the smaller generating units and the breaker voltages are less than 50KV and not part of the transmission grid. Extending this requirement will be costly since the DFR will be located at the transmission network location remote to the multiple generators and low side breakers. The requirement should

Organization	Yes or No	Question 7 Comment
		only include the >200kV circuit breaker SER data.
Response:		
Hydro-Québec TransEnergie (HQT)	No	Sequence of Events requirements should include monitoring of transmission and generator circuit breaker positions, protective relay tripping for all protection groups, and teleprotection keying and receiving.
Response:		
Brazos Electric Power Cooperative, Inc.	No	Need to add clarity to the criteria and do not reference Tables for requirements.
Response:		
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	No	Sequence of Events requirements should include monitoring of transmission and generator circuit breaker positions and protective relay tripping for all protection groups.
Response:		
San Diego Gas and Electric Co.	No	The requirement for collecting SOE data at subs with three or more transmission lines operated at 200kV or above seems a bit stringent for the value received. We would suggest this requirement be put in place for substations with five or more lines operated at 200kV or above.
Response:		
New York Independent System Operator	No	The Loss of generation affects the entire system regardless of interconnection voltage, and just knowing when breakers trip doesn't add enough information. In addition to circuit breaker position change, SOE data should be available for generator protective functions to enable the GO to report the root cause of generator trips which occur due to system disturbances. This is to support possible future blackout investigations and eventually lead to betters standards for generator transmission system coordination. It is very important to capture root cause for units/plants of significant size, and this need is not dependent on interconnection voltage. Change SOE requirement for single unit to 50MVA+, and Plant to 300MVA+. Require SOE to monitor

Organization	Yes or No	Question 7 Comment
		CB positions, protective relay tripping for all protection groups and teleprotection keying and receiving.
Response:		
E.ON U.S.	No	The requirements seem to go beyond what is needed for bulk power system reliability. The requirements appear to prescribe equipment and processes so as to establish conventions that would enable the utility's response to broad operating data requests.
Response:		
Arizona Public Service Co.	No	Requiring sequence of events data for all substations 200 kV and above with 3 or more lines is too stringent. It will provide more data but drowning in data isn't the goal. This should be relaxed to substations with 5 or more lines as these will eliminate the smaller less important substations.
Response:		
JEA	Yes	
Tucson Electric Power	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. This requirement would potentially include a significant number of remote substations. We suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Response:		
Alberta Electric System Operator	Yes	The AESO supports the IRC SRC comments to this question.
Response:		
Beckwith Electric Co	Yes	
Duke Energy	Yes	
CenterPoint Energy	No	CenterPoint Energy disagrees including the proposed sequence of events (SOE) requirements. SOE data is proposed for every change in circuit breaker position (open/close) for EACH circuit breaker in a substation

Organization	Yes or No	Question 7 Comment
		operated at 200kV and above. Such SOE requirements are actually related to SCADA (supervisory control and data acquisition) equipment, not fault and disturbance recording equipment. Such requirements would essentially dictate the specification and the installation, or replacement, of SCADA sets and logic cages. CenterPoint Energy recommends removing SOE requirements from PRC-002. Should the industry determine SOE requirements belong in this standard, CenterPoint Energy recommends SOE recording only be required wherever Fault Recording Data is required. It is present industry practice that Fault Recording Data devices incorporate SOE capability and that SOE data include such information as protective relay pick-up time, as well as breaker interrupting / operating time.
Response:		
Xcel Energy	No	R2 is written such that it appears that the Generator Owner will have to duplicate the SOE recording assigned to the Transmission Owner in R1.2. We assume that was not the SDT's intent, so we recommend that the third and fourth lines of Table 2-1 be modified to read "Each circuit breaker 200 kV and above if not already monitored by the Transmission Owner."
Response:		
Utility System Efficiencies, Inc.	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems overly burdensome. This requirement would potentially include a significant number of remote substations. I suggest that this requirement be for substations with five or more lines operated at voltages between 200 kV and 300 kV and for substations with three or more lines operated at voltages over 300 kV.
Response:		
British Columbia Transmission Corporation	No	The requirement for Sequence of Events data for substations with three or more transmission lines operated at 200 kV or above seems over burdensome. I suggest that this requirement be for substations with five or more lines operated at 200 kV or above.
Kansas City Power & Light	Yes	
PNM	No	The defining sum of lines and transformers should be 4 instead of 3. The sum of 3 will exclude few sites.
Response:		

Requirements related to Fault Recording

8. Requirement R6 states that Fault Recording data shall include a pre trigger record length of at least two cycles and: a post trigger length of at least 50 cycles, or the first three cycles and the final cycle of an event. Do you agree with the requirement? If not, please propose alternate values or requirements and provide rationale.

Summary Consideration:

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	Yes	This requirement allows for the inclusion of legacy equipment. This requirement does not stipulate the recording of adequate information for analysis.
Response:		
IRC Standards Review Committee	No	The SRC questions the need for two seemingly divergent Methods to achieve the reliability data objective. If the objective is to ensure that 2 cycles of pre-event data is available (to establish a base line) then both methods do that. But then Method 1 stores 50 cycles of data and ends (in essence losing all information after that 50 cycles). The second Method saves 3 cycles of post-event data and 2 cycles of data at the end. That means for events lasting longer than 50 cycles Method 1 is missing the end of event information, and Method 2 may not have any data at all after the first two cycles (except for the 3 cycles at the very end of the event). The SRC would ask what is the information that is needed for analysis. Seemingly these two methods are saving different pieces of data and yet both are acceptable. What is the technical basis for the 16 samples per cycle requirement? The SRC would also suggest that Requirement 6 be separated into two independent requirements - one for TOs and one for GOs. Although the intent to combine the two parallel requirements, it is possible for a compliance person to interpret the "AND" as an "inclusive AND" and require the TO (or GO) to have data for both R4 and R5 criteria.
Response:		
SPP System Protection and Control Working Group	No	Recommend to change "first three cycles" to "first six cycles". Six cycles will give you the relay time plus the breaker time.
Response:		

Organization	Yes or No	Question 8 Comment
Members of the WECC Disturbance Monitoring Work Group	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response:		
Southern Company - Transmission	Yes	No further comment.
Response:		
SERC Engineering Committee Planning Standards Subcommittee	No	It is not clear why there are two different requirements for sampling data.
Response:		
SERC Protection and Controls Sub-committee	Yes	Add to the end of the first bullet for the same trigger point?
Response:		
PacifiCorp	Yes	
Dominion	Yes	Add to end of first bullet under R6.1 "for the same trigger point"
Response:		
Bonneville Power Administration	Yes	The number of element criteria may be too stringent, change to 5 elements.
Response:		
FirstEnergy	Yes	
Florida Power & Light	Yes	We agree, however, the term "event" needs to be defined. Please provide a working definition for event.

Organization	Yes or No	Question 8 Comment
Response:		
Los Angeles Department of Water & Power		
MRO NERC Standards Review Subcommittee	No	The first three cycles of an event and the final cycle of an event doesn't seem adequate.
Response:		
PG&E System Protection	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"? We recommend that we use "end of the event" instead.
Response:		
US Bureau of Reclamation	Yes	
NERC	No	The term "final cycle of the event" is confusing. The recording should remain for at least 2 seconds or until the triggered value has been eliminated.
Response:		
TransAlta		
Grant County PUD	Yes	
NYISO	Yes	Yes, this sounds good, but we don't understand how one could record the first 3 cycles and final cycle of an event.
Response:		
Tri-State Generation and Transmission Association	Yes	How is the final cycle of an event determined?

Organization	Yes or No	Question 8 Comment
Response:		
Cowlitz County PUD	Yes	If the former requirement is preferred, would it be best to require all new equipment abide by the 2 - 50 cycle requirement and only allow the first three cycles and the final cycle method for existing legacy equipment? I would not take issue with this when the standard is up for a vote.
Response:		
Portland General Electric	Yes	The following comments are those filed by the DMWG which we are filing in support: The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response:		
Progress Energy Florida	No	Wording is not very clear as to the fault length. An example on how it could be worded would be: "Recording duration shall be at least 50 cycles in total length with a minimum of 2 cycles of pre-fault data (or pre trigger)".
Response:		
Puget Sound Energy	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Schneider Electric	Yes	
Independent Electricity System Operator	No	We do not see the two sets of condition to cover the same period or achieve the same objective. The first condition requires recording that covers a (continuous) period from -2 cycles to +50 cycles of a trigger. In the second condition, the periods covered appear to be (a) -2 cycles to +3 cycles of a trigger, and (b) the last 3 cycles of the "event". Our questions and comments are: i. Are "trigger" and "event" interchangeable? If so, what does R6 mean by "the last cycle of the event" given that there is already a requirement for the +3 cycles of the trigger ii. If they are not interchangeable, what does it mean by an "event" iii. The two conditions appear to require recording different time periods since in the second condition, the recording is not continuous from -2 cycles to +50 cycles of the trigger; as written, it only covers a period of -2 cycles to +3 cycles, then a void until the last cycle of the "event", which is not defined. If however the intent is to record the event 2 cycles before it occurs through to the end of the event, which is hard to define, then we suggest the second bullet be revised as follows: A pre-trigger record length of at least two cycles and a post-trigger record length that extends up until the trigger condition no longer exists. Still we are unable to rationalize how the "first 3 cycles of the event" fit in.

Organization	Yes or No	Question 8 Comment
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	
DTE Energy/Detroit Edison		
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	No	I do not have the expertise to respond to the trigger lengths. However, R6.1 bullet 2, What is an "event"? Is this different from the Disturbance used in R13?
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	The Standard is unclear in the use of the terminology "final cycle of an event". Can this be further defined for clarity of the Standard?
Response:		
Salt River Project	Yes	What is the definition of the "final cycle of an event"?

Organization	Yes or No	Question 8 Comment
Response:		
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	No	Ok with first bullet under R6.1, however, the second bullet refers to "event" without a definition of what constitutes an "event".
Response:		
Hydro-Québec TransEnergie (HQT)	Yes	This requirement allows for the inclusion of legacy equipment. This requirement does not stipulate the recording of adequate information for analysis.
Response:		
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	This requirement allows for the inclusion of legacy equipment. However, this requirement does not stipulate the recording of adequate information for analysis of events that are more complex than a simple fault-trip.
Response:		
San Diego Gas and Electric Co.	Yes	Is there a definition of "the final cycle of an event"? We'd want to make sure that we understand that fully.
Response:		
New York Independent System Operator	No	There is confusion over the meaning to the second option. Does it mean for faults with a duration of greater than 50 cycles this is the minimum record? Or does this allow for use of relays with limited fault recording to be used? Regardless, this record is not equal to the first option. The second record option would be inadequate.

Organization	Yes or No	Question 8 Comment
Response:		
E.ON U.S.	No	Generally, pre-trip data has more analytical value than post-trip data.
Response:		
Arizona Public Service Co.	Yes	If you tell me what the definition of the end of an event is and then I'll be sure to capture the "final cycle" of the event.
Response:		
JEA	No	Various manufacturer's equipment does not presently support this requirement. Special designs and modifications to certain types of relays and fault recording equipment will need to be developed to fully support this requirement, as presently written.
Response:		
Tucson Electric Power	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response:		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments to this question. The AESO would also suggest that the R6 could be revised to require post trigger recording to be "at least 50 cycles post trigger AND the last cycle for extended faults".
Response:		
Beckwith Electric Co	No	This section needs to be rewritten. It is confusing the way it is written with two different options. There is no definition of triggering. As an example: if the triggering is achieved using an input contact (generator/GSU breaker 'a' or 'b' contact) then having 2 cycle pre-tiggering will not capture the required important information and will have 50 cycles of post trigger data which is useless as the breaker has already opened. The other problem is that unlike transmission line relay operations (typically happens much shorter than 50 cycles) the generator relay operations can take several seconds from the inception of fault/abnormal condition (example: loss of field, under frequency, V/Hz, out of step, reverse power etc). Recommend changing the total record

Organization	Yes or No	Question 8 Comment
		length to at least 5 sec with pre and post trigger length selectable based on the triggering mechanism.
Response:		
Duke Energy	Yes	
CenterPoint Energy		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response:		
British Columbia Transmission Corporation	Yes	What is the definition of the "final cycle of an event"?
Response:		
Kansas City Power & Light	No	Do not agree with the notion of data recording of the first 3 cycles and the final cycle. The first three cycles and the last cycle is not sufficient data to be useful for fault recording analysis. At least 6 cycles is needed at the beginning of the record. Although 6 cycles is better, that still does not guarantee sufficient data will be collected in every instance. Recommend the SDT consider changing to capturing 6 cycles.
Response:		
PNM	Yes	

Requirements related to Fault Recording

9. Do you agree with the other Fault Recording requirements in R4 through R6 of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Summary Consideration:

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council	No	Referring to Requirement 4.1, the number of phases to be monitored is excessive. It will not provide any analytical benefit. Monitoring every transmission line in a ring bus is excessive. The second bullet referring to a breaker-and-a-half arrangement needs clarification. What is the "outer bus" in that arrangement? Definitions should be provided when references are made to substation designs or equipment that could have different names or designations in the industry. As we commented in Question 5, we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications. This needs to be reflected in Table 4-1.Referring to Requirement R4.2, the intent of measuring neutral current needs to be clarified, specifically with regard to transformers (see R5.3 in PRC-002-2). Referring to Requirement R5, the comments to R4.1 and R4.2 are applicable. In Table 5-1 the requirements that refer to the high side of critical GSU's should be directed at Transmission Owners, not Generation Owners. Referring to Requirement R6.1, the second bullet does not provide for the recording of adequate information (see response to Question 8).
Response:		
IRC Standards Review Committee	No	The SRC agrees with the data itself. The SRC does not agree that each data item listed in R4 must be an independent requirement. The SRC supports compliance with R4, but that the suggested sub-requirements be bullet items and that those items be handled through VSLs. Similarly with R5, the data items should be bulleted rather than being shown as independent. Similarly with R6, the data items should be bulleted rather than being shown as independent.
Response:		
SPP System Protection and Control Working Group	Yes	

Organization	Yes or No	Question 9 Comment
Members of the WECC Disturbance Monitoring Work Group	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Southern Company - Transmission	Yes	No further comment.
SERC Engineering Committee Planning Standards Subcommittee		
SERC Protection and Controls Sub-committee	Yes	Re-label heading of Table 4-1 to indicate: for substationequipment owned by Transmission Owner?
Response:		
PacifiCorp		
Dominion	Yes	Re-label heading of table 4-1 to indicate:" for substation equipment owned by Transmission Owner"
Response:		
Bonneville Power Administration	No	BPA does not believe the individual phase voltage of each line is required if Bus voltage at the station is recorded. We think the R4.1 may say that, but maybe change the wording order to "The three phase to neutral voltages on each main bus or monitored line as follows:", It shouldn't be required to monitor the voltages on a transfer bus in a main and auxiliary (transfer) bus scheme. The number of element criteria may be too stringent, change to 5 elements.
Response:		
FirstEnergy	Yes	
Florida Power & Light	Yes	

Organization	Yes or No	Question 9 Comment
Los Angeles Department of Water & Power		
MRO NERC Standards Review Subcommittee	Yes	Table 5-1 has a type-o - Row 2, Column 2, bullet 1 extra 'd'.
Response:		
PG&E System Protection	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response:		
US Bureau of Reclamation	Yes	
NERC	No	R4.1 It is important for forensic analysis to have both bus and line quantities for DFR quantities. Bullets 2 and 3 should read: On breaker-and-a-half arrangements, the outer bus voltages, and the individual line voltages. On straight buses, common bus voltages and the individual line voltages.
Response:		
TransAlta		
Grant County PUD	Yes	
NYISO	No	R4.1 requires monitoring of 3 phase voltages on all bus sections of ring buses. We believe this is excessive. Reduce requirements to enough to be able derive all the quantities during normal maintenance conditions (outages).R5.5, second row in table: This puts the responsibility to monitor a transmission substation on the generator owner. Change the requirement such that the substation owner needs to monitor this.
Response:		
Tri-State Generation and Transmission Association	No	The R4.1 and R5.4 ring bus requirements to monitor three-phase voltages on each transmission line seems unnecessary for reliability or for post-event analysis. Voltages from opposite locations on a ring bus should

Organization	Yes or No	Question 9 Comment
		ensure that sufficient quantities are available to perform any required calculations.
Response:		
Cowlitz County PUD	Yes	
Portland General Electric	No	The following comments are those filed by the DMWG which we are filing in support: Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response:		
Progress Energy Florida	No	Monitoring of GSU transformer currents on units >500MVA is the correct approach. However, peaking generation locations will have many generating units of less than 500MVA. The aggregate combination of 1500MVA will encompass many GSU transformers. Monitoring of each of the GSUs' currents (even though they are >200kV) will require extensive DME equipment additions at locations remote to the transmission network where the DME equipment is (and should be) located. We believe these total aggregate generation currents should be monitored at the location where they are introduced to the transmission network. This location may be at an exit point from a generating unit bus or a transmission line the feeds the generation power into another remote transmission substation bus.
Response:		
Puget Sound Energy	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response:		
Schneider Electric	Yes	
Independent Electricity System Operator	No	Please see our comments on R6, above.
Response:		

Organization	Yes or No	Question 9 Comment
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	No	Section R4.1Recommend changing the first bullet to read On ring buses, the voltages of bus sections connected to transmission lines, or the individual line voltages. Section R4.2Recommend removing the word transformer from the qualifying sentence and changing the wording to The three phase currents and the residual or neutral currents of each monitored element as noted in Table 4-1.Table 4-1Recommend changing the single generating unit level to 750MVA or higher to avoid unnecessary Fault Recording Equipment installations. Section R5.1Recommend removal of language restricting the location of where to monitor for three phase to neutral voltages or phase to phase voltages associated with the GSU. Statement should allow for monitoring at T-line level as well. Section R5.2Recommend removal of language restricting the location of where to monitor for three phase to neutral voltages or phase to phase voltages associated with the GSU. Statement should allow for monitoring at T-line level as well. Section R5.4Recommend changing the first bullet to read On ring buses, the voltages of bus sections connected to transmission lines, or the individual line voltages. Section R5.5Recommend removing the word transformer from the qualifying sentence and changing the wording to The three phase currents and the residual or neutral currents of each monitored element as noted in Table 4-1.Table 5-1Recommend changing the single generating unit level to 750MVA or higher to avoid unnecessary Fault Recording Equipment installations.
Response:		
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	No	Comments on PRC-002-2---Disturbance Monitoring and Reporting Requirements Draft 1, January 30, 2009 1. Requirement R5.4: Requirements identified in this section for monitoring bus and line voltages belong to TO and not to GO unless GO owns the Substation. The revision should clearly state that.2. Requirement R5.4: We heard during the Q&A session of the webinar on 3/12/09 that GSU neutral current can be recorded by the residual current (sum of three phase currents). The revision should clearly state that. 3. Requirement R5.4: Please clarify that recording of Generator Step Up transformer (GSU) phase currents can be done by deriving these currents from the GSU output breaker(s) currents. The revision should be modified to state this and that the GSU neutral current can be recorded by deriving this current from the GSU output breaker(s) phase currents. (Most of our GSUs are connected to the switchyard thru two output breakers in a ring bus. It makes lot more sense from a schedule and cost view point to use the quantities from the CTs of these output breakers rather than from the GSU CTs. It also makes sense from reliability viewpoint as less cabling means more

Organization	Yes or No	Question 9 Comment
		reliability for the equipment, especially when with less additional cabling/wiring; we are recording the required quantities.) 4. Requirement R5.5: Requirements identified in this section for monitoring line three phase currents and the residual and monitored current belong to TO and not GO unless GO owns the Substation. The revision should clearly state that.
Response:		
NV Energy	Yes	
DTE Energy/Detroit Edison	No	Consider change to allow high side GSU voltage to be monitored at the high side bus of the same voltage. Present wording can be taken to imply that voltage must be monitored directly at GSU high side terminals. Also, can parallel GSUs be allowed to be monitored at a common point rather than individually? Likewise, can two GSUs connected at a common point at 200 kV or above be allowed to be monitored together at the common connection point?
Response:		
Wisconsin Electric	No	In R5.4 and R5.5, the Generator Owner is required to record Fault Recording data for equipment in the substation connected to a generating station of a specified capacity, in addition to that for the GSU. This appears to be an unnecessary duplication of equipment already being monitored by the Transmission Owner in R4. If this is a correct interpretation, we believe this requirement is redundant, and technically and financially unjustified. We strongly oppose requiring duplication of monitoring equipment for the same facility by both Transmission Owners and Generator Owners. Also, In R5.2, the statement is given that the three-phase current data from the "generator bus" is sufficient for monitoring. Does this mean that the three-phase currents from generator current transformers will meet this requirement?
Response:		
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	No	R4.1, Bullet #1 appears too restrictive for a ring bus. It will require a fault recorder on each bus section with a line going to it. This is also a potential conflict with R7, which allows a recorder up to 2 busses away.Table 4-1. Am I correct in assuming that if there is no transformation with both sides >200kV, I do not need recording no matter how many lines are there Same concern with "plant" vs. "site".

Organization	Yes or No	Question 9 Comment
Response:		
PHI (PEPCO Holdings Inc.)	Yes	FR trigering requirements are not addressed.
Response:		
NV Energy (fka Sierra Pacific Resources)	No	Table 4-1 should also be modified to identify Substations containing any combination of five or more elements. See response to Q7 previous.
Response:		
Salt River Project	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response:		
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	No	Monitoring of GSU transformer currents on units >500MVA is the correct approach. However peaking generation locations will have many generating units of less than 500MVA. The aggregate combination of 1500MVA will encompass many GSU transformers. Monitoring of each of the GSUs' currents (even though they are >200kV) will require extensive DME equipment additions at locations remote to the transmission network where the DME equipment is (and should be) located. We believe these total aggregate generation currents should be monitored at the location where they are introduced to the transmission network. This location may be at an exit point from a generating unit bus or a transmission line the feeds the generation power into another remote transmission substation bus.
Response:		
Hydro-Québec TransEnergie (HQT)	No	Referring to Requirement 4.1, the number of phases to be monitored is excessive. It will not provide any analytical benefit. Monitoring every transmission line in a ring bus is excessive. The second bullet referring to a breaker-and-a-half arrangement needs clarification. What is the "outer bus" in that arrangement? Definitions should be provided when references are made to substation designs or equipment that could have different names or designations in the industry. As we commented in Question 5, we do not feel that the

Organization	Yes or No	Question 9 Comment
		200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications. This needs to be reflected in Table 4-1.Referring to Requirement R4.2, the intent of measuring neutral current needs to be clarified, specifically with regard to transformers (see R5.3 in PRC-002-2). Referring to Requirement R5, the comments to R4.1 and R4.2 are applicable. In Table 5-1 the requirements that refer to the high side of critical GSU's should be directed at Transmission Owners, not Generation Owners. Referring to Requirement R6.1, the second bullet does not provide for the recording of adequate information (see response to Question 8).
Response:		
Brazos Electric Power Cooperative, Inc.	No	Clarify criteria and remove Tables.
Response:		
WECC		
Entergy Services, Inc	No	R4.1 should include provisions to exclude 3 phase potential monitoring for line/bus elements employing line protection schemes, such as current differential relaying, where 3 phase potentials are not presently available and would not needed but for the requirements. Adjacent or remote end element monitoring should be allowable for these cases.
Response:		
Northeast Utilities	No	Referring to Requirement 4.1 and 5.4, monitoring the voltage every transmission line in a ring bus is excessive. Referring to Requirement R4.2, the intent of measuring neutral current needs to be clarified, specifically with regard to transformers (see R5.3 in PRC-002-2).
Response:		
San Diego Gas and Electric Co.	Yes	Agree, except for the comment made in question 7 above about changing the SOE criteria from three lines to five lines.
Response:		

Organization	Yes or No	Question 9 Comment
New York Independent System Operator	No	(R4.1) Requiring monitoring 3 phase voltages of all ring bus bus sections is excessive. Reduce requirements to enough to be able derive all the quantities during normal maintenance conditions.(R5.5, second row of table) This puts the responsibility to monitor a transmission substation on the genertator owner. The gen owner likely does not own the transmission substation. Make monitoring this equipment the responsibility or the transmission owner.(following R6.) We note that there is no mention of FR triggering. While this is specific to the various manufacturers trigger algorithms and specific also to the location, there does need to be a statement that the FR is to trigger for near-by faults, system disturbances, and relay operations. While this type of consideration is difficult to address in a standard, it would be misleading to leave out entirely a statement that reliable FR triggering is necessary. We request that the team add a new provision stating that all required FR channels at a location should be recorded whenever a trigger asserts on any one of them.
Response:		
E.ON U.S.	Yes	The SDT should explain the applicability of this requirement to the GO.
Response:		
Arizona Public Service Co.	Yes	There should be a provision for the case if the quantities aren't able to be measured (CT not available for example).In requirement R5.3 it makes the generator owner responsible to record the neutral current of the GSU high voltage winding. Sometimes, generators that have DFRs applied do not have this quantity available as they mostly have access to the low voltage quantities. In addition, if a generator owner has a fault recorder but doesn't have available channels for this additional quantity, he shouldn't be required to drop a channel he feels is important to make room for these mandated channels. For instance, one only needs two voltages and two currents to measure MW so a generator may have fault recording that measures 2 line voltages and 2 line currents and there may not be room to add the additional channels specified. Generally with two of the values you can derive the third so why force them to record all indicated quantities. These requiremens might be acceptable for new generator installations but there are existing installations that would find this ornerous.
Response:		
JEA	Yes	
Tucson Electric Power	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.

Organization	Yes or No	Question 9 Comment
Response:		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response:		
Beckwith Electric Co	Yes	
Duke Energy	Yes	
CenterPoint Energy	No	The requirements to record all three phase to neutral voltages and all four currents on each transmission line are prescriptive and excessive. The monitoring of two sets of line voltages, in all substation configurations, is a common industry practice which has met the industry's needs. It is unnecessary and excessive to require monitoring of more than two sets of three phase to neutral voltages in any substation arrangement.
Response:		
Xcel Energy	No	As with Question 7, R5 is written such that it appears that the Generator Owner will have to duplicate the fault recording assigned to the Transmission Owner in R4. We assume that was not the SDT's intent, so we recommend that the second line of Table 5-1 include a clarifying statement such as "if not already monitored by the Transmission Owner."
Response:		
Utility System Efficiencies, Inc.	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements operated between 200 kV and 300 kV and for substations with three or more elements operated at voltages over 300 kV. See my response to question 7 above.
Response:		
British Columbia Transmission Corporation	No	Table 4-1 should also be modified to identify Substations containing any combination of five (5) or more elements. See response to question 7 above.
Response:		

Organization	Yes or No	Question 9 Comment
Kansas City Power & Light	No	It is not necessary to require voltages on every line and bus for a ring bus configuration. Suggest requiring at least 33% with a of lines or busses for a ring bus configuration and no less than 2 will be a reasonable assurance there is a voltage collection for fault recording for events. It is unlikely under normal conditions 33% of the lines or busses in a ring would be out of service concurrently. So, for ring configuration stations with up to 6 lines, 2 voltage measures would be required. Ring configuration stations between 7 and 9 lines would require 3 voltage measures. Ring configuration stations with 10 to 12 lines, 4 voltage measures would be required. And so on.
Response:		
PNM	No	R5.3 requires recording current at the neutral bushing of wye-connected GSU transformer high-side windings. That does not have enough value to be a requirement. With the defined time synch. requirements and abundance of recorded voltages correlation of values is accomplished. It may have some value where only low-side generator currents are monitored but not where high-side GSU currents are monitored.
Response:		

Requirements related to Dynamic Disturbance Recording

10. Requirement R7 states that a DDR which is required at a substation meeting the location requirement shall be considered optional if a DDR meeting all of the requirements of R7.1, R7.2, R7.3 and R7.4 is found to be located one or two substations away. Do you agree with this option found in Requirement R7? If no, provide rationale.

Summary Consideration:

Organization	Yes or No	Question 10 Comment
Northeast Power Coordinating Council	Yes	
IRC Standards Review Committee	Yes	The concept of the requirement is good but the wording can be improved. The issue is how to impose penalties for this requirement. If a TO "can" (i.e. the capability is there) get the required data, but the other TO's DDR fails, then who is responsible for compliance? In short, if each TO is responsible for the data then the two substation caveat has no meaning in cases of different TSOs. In the case of the same TSO it may be useful if the two substation limit is justifiable. The SRC suggests rewriting the requirement in a positive fashion. One example would be: "The Transmission Owner of substations 200KV and above shall have access to Dynamic Disturbance Recording data at or within 2 substations of the subject asset or other processes capable of providing:- R7.1- R7.2- R7.3- R7.4 "This proposal changes the requirement into reporting the required data for events that happen within radius of interest (i.e. two substations).
Response:		
SPP System Protection and Control Working Group	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
Southern Company - Transmission	Yes	Southern Company restates its objection to the use of arbitrary location requirements.

Organization	Yes or No	Question 10 Comment
Response:		
SERC Engineering Committee Planning Standards Subcommittee	Yes	
SERC Protection and Controls Sub-committee	Yes	Refer to response in 5.3
Response:		
PacifiCorp	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	The DDR's purpose is for wide area monitoring not as a FR device (although it can help with that). Unless it doesn't interface to a control system (HVDC).
Response:		
FirstEnergy	Yes	
Florida Power & Light	Yes	This needs to be stated more clearly. Could you provide specific examples as part of FAQs.
Response:		
Los Angeles Department of Water & Power	Yes	As stated earlier, similar language can be included to exclude transmission lines and substations that are part of a utilities internal distribution system, and not near intertie point.
Response:		
MRO NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 10 Comment
PG&E System Protection	Yes	
US Bureau of Reclamation	Yes	
NERC	Yes	R7For consistency in description, the DDR requirement in R7 should mirror the station description in R1.1:then for each Substation having any combination of seven or more transmission elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above, the Transmission Owner shall record..."Also, the parenthetical qualifiers in both R7.3 and R7.3 should read: (for each transmission element operated at 200 kV and above)?
Response:		
TransAlta		
Grant County PUD	No	R7 is very difficult to read. A reword similar to is suggested: When a Transmission owner DOES NOT have Dynamic Disturbance Recording (DDR) data meeting all of the requirements of R7.1, R7.2, R7.3, and R7.4, recorded no further than 2 Substations away, then.....
Response:		
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	I find the original verbiage of R7 confusing without the clarifying statement above. I would consider rewording R7.
Response:		
Portland General Electric	Yes	
Progress Energy Florida	Yes	
Puget Sound Energy		

Organization	Yes or No	Question 10 Comment
Schneider Electric	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	Repeating DDR across multiple adjacent substations does not add reliability value. Again, clarity is needed to address this requirement in the context of multiple voltage yards within a substation fence.
Response:		
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	
DTE Energy/Detroit Edison	Yes	
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	See concern in Q9 for R4.1, Bullet 1.
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific	Yes	

Organization	Yes or No	Question 10 Comment
Resources)		
Salt River Project	Yes	
Pacific Northwest National Laboratory	Yes	Yes, but ONLY if the subject substation does not interface to a major control system which cannot be fully monitored from the ac side.
Response:		
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	Yes	Agree with the criterion of adjacent station coverage consistent with comments on 5.3.
Response:		
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
E.ON U.S.		
Arizona Public Service Co.	Yes	
JEA	Yes	

Organization	Yes or No	Question 10 Comment
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	The AESO supports the IRC SRC comments.
Response:		
Beckwith Electric Co	Yes	
Duke Energy	Yes	
CenterPoint Energy	No	CenterPoint Energy disagrees criteria for Dynamic Disturbance Recording (DDR) should be solely based upon the number of connected lines at a substation. In addition to the number of lines, CenterPoint Energy recommends that DDR equipment be required only in substations that have direct interconnections to generating units. By locating DDR capability at generating plants, sufficient DDR data will be available to analyze system disturbances.
Response:		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	Yes, but ONLY if the subject substation does not interface to a major control system which cannot be fully monitored from the ac side.
Response:		
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	No	Does R7 require DDR at all substations one station away from the substation meeting the location requirement?
Response:		
PNM	Yes	

Requirements related to Dynamic Disturbance Recording

11. Requirement R8 states that Generator Owners shall record or have a process in place to derive DDR data for generating plants with an aggregate of 1500 MVA nameplate rating or higher. Do you agree with these values? Please provide supporting documentation for these values or (if you disagree with the values) alternate values and their technical basis.

Summary Consideration:

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council	No	Referring to Requirement R7, is a Generator Owner required to install a DDR if there is a DDR installed on the plant's outlet transmission system no further than two substations away? What is the basis for the "two Substations away" criteria?
Response:		
IRC Standards Review Committee	No	The SRC agrees with the concept of the requirement .The SRC does not agree that the specified data items should be treated as independent requirements. Further, the SRC suggests that the phrase "physical aggregate" be used.
Response:		
SPP System Protection and Control Working Group	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
Southern Company - Transmission	No	Southern Company disagrees with utilization of arbitrary values to determine placement of disturbance monoritoring equipment. As we have previously stated in our comments, the determination of "where" to

Organization	Yes or No	Question 11 Comment
		locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid in accordance with a NERC defined methodology.
Response:		
SERC Engineering Committee Planning Standards Subcommittee	Yes	
SERC Protection and Controls Sub-committee	Yes	
PacifiCorp	Yes	We agree regarding the facility rating. However, Generator owners and Tranmission owners should be permitted to jointly (by contract) apply a "not more than two bus removed" criteria for siting purposes. In that way duplication can be avoided where there is adequate overlap between generation and tranmission locations. We also support WECC's comments responsive to this question.
Response:		
Dominion	Yes	Reword R8 to indicate clarifythat the 1500 MVA aggregate nameplate rating includes only generation connected at 200 kV (high side of GSU) and above and that any generators at the same facility connected at less than 200 kV are not to be included.
Response:		
Bonneville Power Administration	Yes	Yes, but BPA does not necessarilly think each GSU needs it. Some GSU's are parralleled onto a single circuit to integrate into the substation. If it's monitored at the substation that should be good.
Response:		
FirstEnergy	Yes	Our "yes" response is based on the fact that we have no strong technical reason to deviate from the values proposed by the SDT. In review of our own FirstEnergy footprint, the proposed value of 1500 MVA would exempt our single unit nuclear generation facilities. We would like to better understand the technical rationale used by the SDT in choosing this value, and the SDT may want to consider lowering this value to 1000 MVA (single) and adding "over 2000 MVA (multiple units)" to assure that the some single-unit nuclear plants will be

Organization	Yes or No	Question 11 Comment
		required to record dynamic disturbances.
Response:		
Florida Power & Light	Yes	
Los Angeles Department of Water & Power		
MRO NERC Standards Review Subcommittee	Yes	
PG&E System Protection	Yes	The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
US Bureau of Reclamation	Yes	
NERC	Yes	
TransAlta	No	To use a specifie number may not be approperiate way. Please see the comments in Q4 for justification.
Response:		
Grant County PUD		
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	

Organization	Yes or No	Question 11 Comment
Portland General Electric	Yes	The following comments are those filed by the DMWG which we are filing in support: The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
Progress Energy Florida	Yes	
Puget Sound Energy	Yes	The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
Schneider Electric	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 11 Comment
DTE Energy/Detroit Edison	No	Please see comments for 5.1. Also, consideration should be given to applying the "one or two substations away" option to R8 if the entire plant output connects to stations with DDRs.
Response:		
Wisconsin Electric	No	In R8, the Generator Owner is required to record Dynamic Disturbance Recording (DDR) data for generating stations with a capacity of 1500 MVA or higher. This size requirement is already utilized to require monitoring of Fault Recording data in R5. DDR monitoring is more specialized and should be required at fewer facilities than Fault Recording data. For this reason we believe that the DDR requirement in R8 should only apply at aggregate facilities having a capacity of 2000 MVA or higher.
Response:		
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	Same concern with "plant" vs. "site".
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	Some clarity is needed with regard to whether the requirement is met if the GO does not own the switchyard, but the data is being recorded by the TO owning the switchyard.
Response:		
Salt River Project	Yes	
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	No	Referring to Requirement R7, is a Generator Owner required to install a DDR if there is a DDR installed on the plant's outlet transmission system no further than two substations away? What is the basis for the "two

Organization	Yes or No	Question 11 Comment
		Substations away" criteria?
Response:		
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	No	It's possible for remote locations in a system to have a high concentration of generation spread across several busses. It would seem appropriate to require recorders in such areas.
Response:		
San Diego Gas and Electric Co.	Yes	You might want to address the potential issue of different ownership between the generator and the attached substation, and what that does to the requirements.
Response:		
New York Independent System Operator	Yes	
E.ON U.S.	No	E ON US recommends use of an aggregate nameplate value for generating plants of 2000 MVA or higher, as recommended in Standard EOP-004 Disturbance Reporting.
Response:		
Arizona Public Service Co.	No	If the majority of the 1500 MVA of the plant is recorded, smaller units that are not significant (300 MVA or less) shouldn't be required to be monitored regardless of what voltage level they connect at. Perhaps the requirement could be changed such that if more than 50% of the plant (by MVA) is recorded, units smaller than 300 MVA could be excluded. A generator owner may have a plant that exceeds 1500 MVA when aggregated but this could be due to a few large units, with other smaller units included that are not of consequence.

Organization	Yes or No	Question 11 Comment
Response:		
JEA	Yes	
Tucson Electric Power	Yes	The requirement is not clear that If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, whether this meets the requirement. What if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Duke Energy	Yes	
CenterPoint Energy		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	If the generator owner does not own the switchyard, but the data is being recorded by the switchyard owner, this requirement is not clear whether this situation would meet this requirement. Also, what if a plant is greater than 1500 MVA but less than 1500 MVA of the plant connects to a transmission system at greater than 200 kV? Is this standard applicable to this plant?
Response:		
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	

Requirements related to Dynamic Disturbance Recording

12. Do you agree with the other Dynamic Disturbance Recorder requirements in R7 through R11 of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Summary Consideration:

Organization	Yes or No	Question 12 Comment
Northeast Power Coordinating Council	No	Referring to Requirement R7, because of the limitations of legacy equipment, this requirement will not be met. Referring to Requirement R8, as noted in the response to Question 5 and elsewhere, we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications. Referring to Requirement R8.4, the statement in parenthesis "(per each monitored element)" is redundant.We have no comment to Requirement R9. Our response to Question 2 deals with Requirement R10.Requirement R11 should be reworded to: that does not have continuous recording capability shall set its device to trigger and record according to the following where available: Requirement R11.1 should be worded to:R11.1 For rate-of-change of frequency, or delta frequency. Legacy equipment might not be able to satisfy Requirement R11.3.
Response:		
IRC Standards Review Committee	No	The SRC agrees with the other DDR requirements in R7 through R10, but do not agree with and specifically have a question on R11.1. R11 requires TO and GO to set their DDRs (that do not have continuous recording capability) to trigger under specific conditions. R11.1 simply states for rate-of-change of frequency only, but does not specify what rate is it that the DDR should be triggered to start recording. Do we need a default frequency rate-of-change to be specified in R11.1?No, the identified items need not be assigned as independent subrequirements.For R10, the implementation caveat should not be part of the requirement. Rather it should be included as part of the Implementation Plan.The SRC would also suggest that Requirement 9 be separated into two independent requirements - one for TOs and one for GOs. Although the intent to combine the two parallel requirements, it is possible for a compliance person to interpret the "AND" as an "inclusive AND" and require the TO (or GO) to have data for both R7 and R8 criteria.
Response:		
SPP System Protection and Control	No	1) Please clarify R 10 and R 11 with respect to date (January 1, 2011). One suggestion is to have R11 listed before

Organization	Yes or No	Question 12 Comment
Working Group		R10.2) Specify the actual trigger value in R 11.1
Response:		
Members of the WECC Disturbance Monitoring Work Group	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response:		
Southern Company - Transmission	Yes	Southern Company supports the comments submitted by the SERC PCS for this question.
Response:		
SERC Engineering Committee Planning Standards Subcommittee		
SERC Protection and Controls Sub-committee	Yes	To make this clearer, reword R.7 to start with location requirements rather than exceptions. Also, under R11.3, the pre-trigger record length and post-trigger record length should be specified (whatpart of the 3 minutes should be pre and post trigger?).
Response:		
PacifiCorp	No	The installed equipment of the neighboring (interconnected) entity should be included in the parameters of R7 "..no further than two substations away..". to provide an overlay between Tranmission owners. Similar to comment 11. above. We also support WECC's comments responsive to this question.
Response:		
Dominion	Yes	To make this clearer, reword R.7 to start with location requirements rather than exceptions. If we use a table under R1 and R4 then use a similar table under R7. Also, under R11.3, the pre-trigger record length and post-trigger record length should be specified (what part of the 3 minutes should be pre and post trigger).We suggest that the

Organization	Yes or No	Question 12 Comment
		pre-trigger and post-trigger be a minimum of 1 minute each with total record at least 3 minutes
Response:		
Bonneville Power Administration	No	R9.2 Change to clarify "Sampling" (vs. "collecting") at 960 samples/second, in the slide presentation.R11.2 BPA does not think the oscillation trigger is viable - remove this requirement, or indicate better that if an optional oscillation detector is installed then set it per R11.2 requirements. Change R12 to say " shall time synchronize all of its Allow for additional/future triggers, frequency set point level vs. rate of change. Change R11.3 to have record length include pre-trigger event of 30 seconds to 1 minute.
Response:		
FirstEnergy	Yes	
Florida Power & Light	Yes	The term continuous recording should be technically defined. Obviously a true continuous record can not be retrieved or stored locally for long periods. Continuous records must be retrievable in sections. The expectations of continuous recording need to be well defined to determine compliance if for no other reason to provide audit ability.
Response:		
Los Angeles Department of Water & Power		
MRO NERC Standards Review Subcommittee	Yes	
PG&E System Protection	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response:		

Organization	Yes or No	Question 12 Comment
US Bureau of Reclamation	Yes	
NERC	No	R7For consistency in description, the DDR requirement in R7 should mirror the station description in R1.1: then for each Substation having any combination of seven or more transmission elements consisting of transmission lines operated at 200 kV or above or transformers having primary and secondary voltage ratings of 200 kV or above, the Transmission Owner shall record..."The parenthetical qualifiers in both R7.3 and R7.3 should read: (for each transmission element operated at 200 kV and above) R9.2 The term collect in the sample rate requirement of R9.2 can be confused with what is required for values required to be stored. R 9.3 speaks to storage reuquirements. For clarity, R9.2 should read: Sample at least 960 times per second to calculate RMS electrical quantities.
Response:		
TransAlta		
Grant County PUD	Yes	
NYISO	No	We agree with the minimum requirements set in R9 for all DDRs.R11.1 What is supposed to be captured with this trigger? A ROC trigger won't consistantly capture the events causing step changes in frequency. A delta frequency trigger is more effective for capturing drops/rises in frequency. We propose requiring a trigger for delta frequency/step change in frequency for all new equipment, and for existing equipment that meets R9 and has the capability.R11.2 Not all existing recorders have this capability. Require this trigger for existing recorders that meets R9 and has the cabability.R11.3 Not all existing recorders have this capability. Require 3 minute recordings for existing equipment with this capability, and 60 second post trigger recordings for existing recorders that meet R9, but cannot store 3 minute records.
Response:		
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	
Portland General Electric	No	The following comments are those filed by the DMWG which we are filing in support: The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability

Organization	Yes or No	Question 12 Comment
		purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirment eliminates the use of this adequate equipment.
Response:		
Progress Energy Florida	Yes	
Puget Sound Energy	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirment eliminates the use of this adequate equipment.
Response:		
Schneider Electric	No	The need to record and store continuously captured waveforms seems to be in excess. Triggered waveforms would suffice. Why the need to continuously record?
Response:		
Independent Electricity System Operator	No	We agree with the other DDR requirements in R7 through R10, but do not agree with/have a question on R11.1. R11 requires TO and GO to set their DDRs (that do not have continuous recording capability) to trigger under specific conditions. R11.1 simple states for rate-of-change of frequency only, but does not specify what rate is it that the DDR should be triggered to start recording.
Response:		
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	

Organization	Yes or No	Question 12 Comment
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	No	I agree with the terms. However, nothing is mentioned in the standard about the acceptable format that the DDR continuous data must be. The WECC uses the BPA stream reader format, while others use the IEEE C37.118-2006 format. I think this is the place to state and consolidate formats, similar to the COMTRADE requirement for the fault recorder data.
Response:		
DTE Energy/Detroit Edison	No	Please see comments for 9.
Response:		
Wisconsin Electric		
ITC Transmission, METC	No	R9.1 is redundant to R7.3, R8.3 which indicate that the current monitored is required to be from the same phase as the voltage monitored. This redundant requirement may lead to double jeopardy.
Response:		
City of Tallahassee (TAL)		No expertise to provide input.
Response:		
PHI (PEPCO Holdings Inc.)	Yes	It should be clarified that if all 3 phase bus voltages are monitored, the monitored phase current for each of the lines do not all have to be on the same phase.
Response:		

Organization	Yes or No	Question 12 Comment
NV Energy (fka Sierra Pacific Resources)	No	Sample rate of 960 samples per second in R9.2 is higher than is needed for reliability and would antiquate the investment already made at numerous substations. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the Glossary and the 960 samples per second requirement precludes the use of this existing equipment.
Response:		
Salt River Project	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response:		
Pacific Northwest National Laboratory	No	12A. The term "collect" in R9.2 seems unclear--does it mean "measure and store (for subsequent off-line analysis)," or does it mean "measure as an input for on-line RMS caluculations" 12B. For either interpretation of R9.2, the 960 sps requirement is an arbitrary value that seems unnecessarily high. The WECC WAMS contains DDR units that usually record point-on-wave and controller data at 960 sps, but these units also produce quite usable records when operated at 240 sps--what are the information targets, and what are the cost constraints? Phasor measurement units and other digital transducers can produce quite acceptable data with input rates below 960 sps, ESPECIALLY if their output rate is a mere (and unacceptably low) 6 sps.12C. In R9.3, 6 sps recording is almost too slow to be useful in a DDR. R6.2 requires at least 16 samples per 60 Hz cycle in fault recording--it is not unreasonable to seek a similar number of samples for each cycle of the highest swing frequency that a DDR should record. This rounds off nicely at 30 sps.12D. Extend R10 to read ". . . continuous recording at 30 sps. Future versions of this Standard may require 60 sps at some locations."12E. Consider specifying additional triggers in R11.1 (continued frequency offsets, steps in voltage or line flow, manual triggers, . . .)12F. Change R11.3 to read "Set data record lengths at a minimum of three minutes, plus at least one minute of pre-trigger data." A further requirement for trigger continuation should be considered for persistent oscillations or continued frequency offsets.
Response:		
Progress Energy Carolina, Inc.	Yes	

Organization	Yes or No	Question 12 Comment
Hydro-Québec TransEnergie (HQT)	No	Referring to Requirement R7, because of the limitations of legacy equipment, this requirement will not be met. Referring to Requirement R8, as noted in the response to Question 5 and elsewhere, we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications. Referring to Requirement R8.4, the statement in parenthesis "(per each monitored element)" is redundant. We have no comment to Requirement R9. Our response to Question 2 deals with Requirement R10.Requirement R11 should be reworded to: that does not have continuous recording capability shall set its device to trigger and record according to the following where available: Requirement R11.1 should be worded to:R11.1 For rate-of-change of frequency, or delta frequency. Legacy equipment might not be able to satisfy Requirement R11.3.
Response:		
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	No	R10 states DDR devices installed after 1-1-11 shall be capable of continuous recording. It is not clear when continuous recording would be required to begin.
Response:		
Northeast Utilities	No	Referring to Requirement R7, because of the limitations of legacy equipment, this requirement will not be met. Referring to Requirement R8, it's possible for remote locations in a system to have a high concentration of generation spread across several busses. It would seem appropriate to require recorders in such areas. Referring to Requirement R8.4, the statement in parenthesis "(per each monitored element)" is redundant. Referring to Requirement R9.3, does this need to be stored if the values can be derived from the record Response to Question 2 deals with Requirement R10.Requirement R11 should be reworded to: that "does" not have continuous recording capability shall set its device to trigger and record according to the following "where available": Requirement R11.1 should be worded to:R11.1 For rate-of-change of frequency, or delta frequency. Legacy equipment might not be able to satisfy Requirement R11.3.
Response:		
San Diego Gas and Electric Co.	No	The requirement in R9.2 to collect 960 samples per second seems high for the purpose of reliability.

Organization	Yes or No	Question 12 Comment
Response:		
New York Independent System Operator	No	(R9) We request that the team add a new provision stating that all required DDR channels at a location should be recorded whenever a trigger asserts on any one of them, even where the channels are distributed across multiple DDR units.(R10) what exactly do the words "to meet requirements R7, R8, and R9" have to do with all this? We propose removing the reference to R7, R8, R9 and simply require continuous recording ability for newly installed DDRs The requirement of recorders installed after Jan 1, 2011 being able to continuously record would be redundant for the NPCC which requires recorders installed after Jan 1, 2009 to be continuous recorders. This will lead to confusion for some people and we propose adding some words describing such a situation and clarifying the requirements in such a case.(R11.1) It is our experience that rate-of-change in frequency is actually not a good DDR trigger. It produces many records for highly local events and may not catch significant disturbances. Delta Frequency is a proven DDR trigger, and performed admirably during the 2003 blackout. A good guideline for a delta frequency trigger would be to set to detect a sudden frequency change of 20 mHz. We suggest R11.1. should be written for delta frequency triggering with the aforementioned guideline for setting. Rate-of-change in frequency should not be mentioned in this standard. Rate-of-change in frequency is not a general name which includes delta frequency. (Refer to FDAC www.truc.org 2006 Conference paper: Frequency Triggers.)(R11.2) Not all existing recorders have this capability. Require this for existing recorders that have the capability and future installations.(R11.3) Not all existing recorders have this capability. Require minimum of 3 minutes for recorders with the capability, and 60 seconds for the minimum post trigger record length for all others.
Response:		
E.ON U.S.	No	The GO should be required to collect current and voltage data relative to the triggering event (i.e. change of breaker position). The format should be given in either CSV or plain text, which can be analyzed by any system. Rather than having all time-stamped current and voltage data recording equipment accommodate a certain IEEE format, the available data could be submitted in CSV/plain text and later analyzed in the IEEE format. Also, in Section A part 5 of the standard, the effective date for both 50% and 100% compliance is stated as [t]he first day of the first calendar quarter four years after applicable Regulatory Approval It would be more reasonable to require 100% compliance in, for example, 8 years and Irequire 50% compliance in 4 years. This would allow sufficient time to do the necessary engineering, acquiring of equipment, etc. to meet the requirements of this standard.
Response:		
Arizona Public Service Co.	No	R9.2 requires sampling at 960 samples per second. There are many DDR devices in service presently that have lower sample rates that provide perfectly adequate data. For example, there are many Macrodyne PMUs in service

Organization	Yes or No	Question 12 Comment
		that have a 720 Hz sample rate and a data storage rate of 30 Hz. These PMUs should either be grandfathered or requirement should be reduced to allow them to meet the criteria. Don't require people to replace adequate equipment that gives acceptable results.
Response:		
JEA	Yes	
Tucson Electric Power	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response:		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response:		
Beckwith Electric Co	Yes	
Duke Energy	Yes	
CenterPoint Energy		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes a DDR frequency response of 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second (point on wave) provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and this change to require 960 samples per second eliminates the use of this adequate equipment.12A. The term "collect" in R9.2 seems unclear--does it mean "measure and store (for subsequent off-line analysis)," or does it mean "measure as an input for on-line RMS calculations?" 12C. In R9.3, 6 sps recording is almost too slow

Organization	Yes or No	Question 12 Comment
		to be useful in a DDR. R6.2 requires at least 16 samples per 60 Hz cycle in fault recording--it is not unreasonable to seek a similar number of samples for each cycle of the highest swing frequency that a DDR should record. This rounds off nicely at 30 sps.12D. Extend R10 to read ". . . continuous recording at 30 sps. Future versions of this Standard may require 60 sps at some locations."12E. Consider specifying additional triggers in R11.1 (continued frequency offsets, steps in voltage or line flow, manual triggers, . . .)12F. Change R11.3 to read "Set data record lengths at a minimum of three minutes, plus at least one minute of pre-trigger data." A further requirement for trigger continuation should be considered for persistent oscillations or continued frequency offsets.
Response:		
British Columbia Transmission Corporation	No	The 960 samples per second (R9.2) is higher than is needed for reliability. Typical DDR equipment collects 30 samples per second. For reliability purposes 0.1 to 3 Hz is sufficient (see NERC Glossary definition for Disturbance Monitoring Equipment) and 30 samples per second provides the required resolution for this frequency range. PMU equipment is adequate to meet the DDR definition in the NERC Glossary and the 960 samples per second requirement eliminates the use of this adequate equipment.
Response:		
Kansas City Power & Light	No	R10 is part implentation plan or effective date and part requirement. The requirement is a DDR device capable of continuous recording to meet requirements R7 through R9. The effective date is January 1, 2011. Request the SDT remove the effective date part from R10 and put that in section A. In addition, the Effective Date part of Section A is either incorrect or may be conflicting with the January 1, 2011 expectation by including R11 with a 50% compliance in two years and 100% compliant in four years after regulatory approval. Please consider the intentions and revise the Effective Date part of Section A to accurately reflect the SDT intentions regarding implementation of the requirement part of R10.
Response:		
PNM	No	

General Questions

13. Do you agree with the Other Disturbance Monitoring Requirements R12 and R13 of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Summary Consideration:

Organization	Yes or No	Question 13 Comment
Northeast Power Coordinating Council	Yes	
IRC Standards Review Committee	No	The SRC questions the use as Universal Coordinated Time in R12 as a reliability issue. Having UCT for every device may make it "easier" for an after-the-fact collection of DDR data, it does not address the fact that other data would not be on UCT, and that a team should be able to adjust for time differences rather than to subject someone to financial penalties even though it had the data it did not have the proper time zone defined.
Response:		
SPP System Protection and Control Working Group	Yes	1. Please clarify the definition of Disturbance. Is it according to Table 1 in EOP-004-1?
Response:		
Members of the WECC Disturbance Monitoring Work Group	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response:		
Southern Company - Transmission	Yes	No further comment.
SERC Engineering Committee Planning Standards Subcommittee		
SERC Protection and Controls Sub-committee	Yes	

Organization	Yes or No	Question 13 Comment
PacifiCorp	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Florida Power & Light	Yes	Please see comments for question 17.
Response:		
Los Angeles Department of Water & Power		
MRO NERC Standards Review Subcommittee	Yes	
PG&E System Protection	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response:		
US Bureau of Reclamation	Yes	
NERC	Yes	
TransAlta		
Grant County PUD	Yes	
NYISO	Yes	
Tri-State Generation and	No	Data should be retained longer than 10 calendar days. We would suggest 60 days as a minimum.

Organization	Yes or No	Question 13 Comment
Transmission Association		
Response:		
Cowlitz County PUD	Yes	
Portland General Electric	Yes	The following comments are those filed by the DMWG which we are filing in support: The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response:		
Progress Energy Florida	Yes	
Puget Sound Energy	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response:		
Schneider Electric	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 13 Comment
DTE Energy/Detroit Edison		
Wisconsin Electric	No	The intent of R13 is not clear to us. This seems to be a data retention requirement.
Response:		
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	No	R13; The NERC definition of Disturbance is too vague for this standard. Any minor hiccup on the grid or even local area could be interpretted as a Disturbance.
Response:		
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response:		
Pacific Northwest National Laboratory	Yes	In R12, bear in mind that DDR units which are closely synchronized at their INPUTS are not necessarily synchronized at their OUTPUTS. E.g., the processing lag through a PMU can vary by 30 msec or more between different PMU types even when they are all operating at 30 sps. If properly filtered, the relative processing delay for 6 sps data would probably be something like 50 msec. These timing inconsistencies can be very important when developing an integrated profile of system dynamic behavior.
Response:		
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	

Organization	Yes or No	Question 13 Comment
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	Referring to Requirement R13, it could be read to mean that one only needs to keep data for 10 days. We believe it was intended to say the device shall have the storage to retain records for 10 days.
Response:		
San Diego Gas and Electric Co.	No	In R12, the criteria is to synchronize SOE, FR, and DDR functions to within +/- 2ms of UTC, but earlier in R3, the criteria for time-stamping changes in breaker position is to be within 4ms of UTC. We would suggest making both of the criteria to be within 4ms of UTC.
Response:		
New York Independent System Operator	No	(R12) This requirement mainly concerns synchronizing with UTC Time Scale. The words with the associated hour offset have to do with Time Zone and should be removed from this sentence and placed in a separate sentence or a separate requirement. We suggest keeping these two concepts separate, both in the interest of clarity, and to facilitate future adjustments in wording. This area is covered in the report of IEEE PSRC I11 which is among the drafting team references. Two acceptable separate sentences or requirements would be as follows: Each TO and GO shall synchronize all of its SOE, FR, and DDR functions to within +/- 2 milliseconds of Universal Coordinated Time (UTC) Time Scale. Within time sequence data files produced by SOE, FR, and DDR functions, and within filenames, time shall be expressed in 24 hour format, and with no local offset, or with some number of positive or negative local hour(s) of local offset. Each filename, in conforming to C37.232-2007 COMNAMES (See D. 1.5.1) must contain this offset information. Since C37.111-1999 COMTRADE does not include the offset within the .cfg file, and until this issue is addressed in a revision to COMTRADE, the offset in the filename shall be interpreted, for purposes of compliance with this standard, to apply to the time sequence data in the file. On the last point, the drafting team is perhaps aware that an IEEE PSRC working group H4 is making revisions to C37.111-1999 COMTRADE, and is considering addition of local offset to the COMTRADE .cfg file.
Response:		

Organization	Yes or No	Question 13 Comment
E.ON U.S.	No	E ON US objects to the compliance timetable of immediate to 18 months after NERC Board of Trustees or FERC approvals. More time is required to properly design, procure and install the disturbance monitoring equipment necessary to meet the proposed requirements, particularly in light of the uniqueness of the existing facilities and equipment to which the requirements apply.
Response:		
Arizona Public Service Co.	No	Earlier in R3 you specify +/- 4 ms
Response:		
JEA	No	Certain DFR equipment, especially microprocessor relays used for DFR functionality, have limited storage. The relay equipment storage buffers for oscillographic information may be overwritten by new data in a roll over buffer and will not be available for the 10 day period. For SOE and DDR data the ten day storage requrienment should be easily met, but not for relay DFR equipment.
Response:		
Tucson Electric Power	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response:		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response:		
Beckwith Electric Co	Yes	
Duke Energy	Yes	DDR data will overwrite after 10 days, in some instances.
Response:		
CenterPoint Energy	No	The FERC-approved NERC reliability standard FAC-003 for Vegetation Management includes allowances for certain situations resulting from natural disasters, such as tornados and hurricanes. This proposed standard does

Organization	Yes or No	Question 13 Comment
		not address the enormous quantities of data, as well as the complications, that arise in such natural disasters. CenterPoint Energy recommends reviewing the various requirements and including appropriate allowances to address natural disaster situations.
Response:		
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.Also, in R12, bear in mind that DDR units which are closely synchronized at their INPUTS are not necessarily synchronized at their OUTPUTS. E.g., the processing lag through a PMU can vary by 30 msec or more between different PMU types even when they are all operating at 30 sps. If properly filtered, the relative processing delay for 6 sps data would probably be something like 50 msec. These timing inconsistencies can be very important when developing an integrated profile of system dynamic behavior and should be addressed by this Standard.
Response:		
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	No	It is not possible to guarantee DME data will be available 10 calendar days after an event in R13. Considering the number of triggers involved setting off the collection of relevant date and the collection of relevant data and the limits of the storage of DME equipment, it is possible in storm situations where there can be so many triggered instances, the data for an event of interest may not be present. Request the SDT consider revising this requirement to require entities to retreive the DME data that is stored (either remotely or locally) within 10 calendar days of an event. What this does is remove the requirement to ensure the data of interest is there and emphasizes the need to retrieve data before it is lost. In addition, please clarify the definition of a "Disturbance" referred to in R13. Is it according to Table 1 in EOP-004-1?
Response:		
PNM	Yes	

General Questions

14. Are you aware of any regional variances that would be required as a result of the proposed standard?

Summary Consideration:

Organization	Yes or No	Question 14 Comment
Northeast Power Coordinating Council	No	
IRC Standards Review Committee	No	
SPP System Protection and Control Working Group	No	
Members of the WECC Disturbance Monitoring Work Group		
Southern Company - Transmission	No	No further comment.
SERC Engineering Committee Planning Standards Subcommittee	No	
SERC Protection and Controls Sub-committee	Yes	See comment on response #1.
Response:		
PacifiCorp	No	
Dominion	Yes	We support the 200 kV cutoff. However, some regions have indicated the 200kV threshold is not appropriate and

Organization	Yes or No	Question 14 Comment
		indicate a preference for a lower criteria. We believe that if the regions desire to require more granularity, that criteria should be applied in a regional standard which can be more restrictive and should be supported by a technical basis
Response:		
Bonneville Power Administration	No	
FirstEnergy	No	
Florida Power & Light	No	
Los Angeles Department of Water & Power	No	
MRO NERC Standards Review Subcommittee	No	
PG&E System Protection	No	
US Bureau of Reclamation	Yes	
NERC	No	For reasons of consistency in the ability to cross-regional or interconnection-wide disturbance analysis, there should be no regional variances.
Response:		
TransAlta		
Grant County PUD	No	
NYISO	No	
Tri-State Generation and	No	

Organization	Yes or No	Question 14 Comment
Transmission Association		
Cowlitz County PUD	No	Question 14 Comments:
Response:		
Portland General Electric		
Progress Energy Florida	No	
Puget Sound Energy		
Schneider Electric	No	
Independent Electricity System Operator	No	
American Electric Power	No	
NextEra Energy Resources (formerly FPL Energy)	No	
National Grid		
Manitoba Hydro	No	
Exelon Generation LLC	No	
NV Energy		As stated previously, the DDR data format differs from region to region and should be standardized.
Response:		
DTE Energy/Detroit Edison	No	Will regional variances be included in this standard?
Response:		

Organization	Yes or No	Question 14 Comment
Wisconsin Electric	No	
ITC Transmission, METC	No	
City of Tallahassee (TAL)	No	
PHI (PEPCO Holdings Inc.)	Yes	PRC-002-RFC-01, draft 11, requires DM for single generating units 250MVA and above, and/or aggregate plant capacity of 750MVA and above.
Response:		
NV Energy (fka Sierra Pacific Resources)	No	
Salt River Project		
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	No	
Hydro-Québec TransEnergie (HQT)	No	
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	No	Not as proposed, but there should be for DDR applications.
Response:		
Northeast Utilities	No	

Organization	Yes or No	Question 14 Comment
San Diego Gas and Electric Co.		
New York Independent System Operator	No	
E.ON U.S.		
Arizona Public Service Co.		
JEA	No	
Tucson Electric Power		
Alberta Electric System Operator	Yes	
Beckwith Electric Co	No	
Duke Energy	No	
CenterPoint Energy		
Xcel Energy	No	
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		
Kansas City Power & Light	No	
PNM	No	

General Questions

15. Are you aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement?

Summary Consideration:

Organization	Yes or No	Question 15 Comment
Northeast Power Coordinating Council	No	
IRC Standards Review Committee	No	
SPP System Protection and Control Working Group	No	
Members of the WECC Disturbance Monitoring Work Group		
Southern Company - Transmission	No	No further comment.
SERC Engineering Committee Planning Standards Subcommittee	No	
SERC Protection and Controls Sub-committee	No	
PacifiCorp	No	
Dominion	Yes	Concern that FERC standards and code of conducts, as well as some RTO/ISO rules may prohibit the GO from

Organization	Yes or No	Question 15 Comment
		access to system monitoring data necessary to participate in disturbance analysis studies.
Response:		
Bonneville Power Administration	No	
FirstEnergy	No	
Florida Power & Light	No	
Los Angeles Department of Water & Power	No	
MRO NERC Standards Review Subcommittee	No	
PG&E System Protection		
US Bureau of Reclamation	Yes	
NERC	No	
TransAlta		
Grant County PUD		
NYISO	No	
Tri-State Generation and Transmission Association	No	
Cowlitz County PUD	No	
Portland General Electric		

Organization	Yes or No	Question 15 Comment
Progress Energy Florida	No	
Puget Sound Energy		
Schneider Electric	No	
Independent Electricity System Operator	No	
American Electric Power	Yes	The additional costs imposed by implementing this standard represent a financial risk to the utility. In the regulatory process, increased costs in tariffs and rate schedules are evaluated for recovery on a cost-benefit basis by the applicable regulatory authority. Additionally, such costs are subject to regulatory lags in the period before such cases are heard by this authority.
Response:		
NextEra Energy Resources (formerly FPL Energy)	No	
National Grid		
Manitoba Hydro	No	
Exelon Generation LLC	No	
NV Energy	No	
DTE Energy/Detroit Edison		
Wisconsin Electric		
ITC Transmission, METC	No	
City of Tallahassee (TAL)	No	

Organization	Yes or No	Question 15 Comment
PHI (PEPCO Holdings Inc.)	No	
NV Energy (fka Sierra Pacific Resources)	No	
Salt River Project		
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	No	
Hydro-Québec TransEnergie (HQT)	No	
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	No	
Northeast Utilities	No	
San Diego Gas and Electric Co.		
New York Independent System Operator	No	
E.ON U.S.		
Arizona Public Service Co.		WECC has had a disturbance monitoring plan for many years. As part of this plan they have required PMUs at certain locations. The PMUs that were "approved" include some that would not meet the R9.2 requirement as discussed earlier. This would create a conflict between what WECC agreed was acceptable and what this

Organization	Yes or No	Question 15 Comment
		standard proposes.
Response:		
JEA	No	
Tucson Electric Power		
Alberta Electric System Operator	No	
Beckwith Electric Co	No	
Duke Energy	No	
CenterPoint Energy		
Xcel Energy	No	
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		
Kansas City Power & Light	No	
PNM		

General Questions

16. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Summary Consideration:

Organization	Yes or No	Question 16 Comment
Northeast Power Coordinating Council	Yes	Regarding Table 2-1: Generator Owner's Requirement R2 for Sequence of Events Data, as we commented in Question 5 and elsewhere performance based stability studies have identified facilities operated at voltages below 200kV, generators with less than 500MVA capacity, aggregate plants with less than 1500MVA that when lost would have a significant impact on the power system. We do not feel that the 200kV threshold, nor the plant/plants' capacities are appropriate criteria for assessing criticality. This should be reflected in the table. The Applicability Section refers to Transmission Owners with facilities greater than 200kV, and Generator Owners with plants connected at greater than 200kV, capacities greater than 500MVA, aggregate plants with capacities greater than 1500MVA. As we commented in Question 5 and elsewhere we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications.
Response:		
IRC Standards Review Committee	Yes	Compliance item 1.3.2 and 1.5 seem to be adding undocumented requirements. The standard focuses on data collection but does not require the data to be provided to anyone. Is it implied (from the Rules of procedure) that the data be provided to the ERO, and therefore no requirement is needed? Data Retention also adds undocumented requirements. Mandatory formats should not be part of a standard.
Response:		
SPP System Protection and Control Working Group	Yes	1)The proposed standard needs to include a statement to trigger a DFR on a fault. 2)Sections 1.3.2 and 1.5 from Section D (Compliance) are requirements so they need to be added in Section B (Requirement)3) How does the requirements in this proposed standard apply to a substation jointly owned by two or more parties?
Response:		
Members of the WECC Disturbance	Yes	Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not.Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed

Organization	Yes or No	Question 16 Comment
Monitoring Work Group		by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response:		
Southern Company - Transmission	No	No further comment.
SERC Engineering Committee Planning Standards Subcommittee	No	
SERC Protection and Controls Sub-committee	No	
PacifiCorp	Yes	Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files? This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response:		
Dominion		The applicability section of this draft standard is not consistent with NERC's Statement of Compliance Registry Criteria for a TO and GO (i.e., individual generation resources larger than 20 MVA or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher).NERC's Statement of Compliance Registry Criteria states: If an entity is part of a class of entities excluded based on the criteria above as individually being unlikely to have a material impact on the reliability of the bulk power system, but that in aggregate have been demonstrated [emphasis added] to have such an impact it may be registered for applicable standards and requirements irrespective of other considerations.? We therefore recommend that the language referring to voltage and size be removed from the applicability portion of the standard and instead be applied to the requirements within the standard.
Response:		

Organization	Yes or No	Question 16 Comment
Bonneville Power Administration	Yes	
FirstEnergy	Yes	1. The requirements as written may not take into account the actual entity that owns the equipment. If Transmission Owners installed the equipment relevant to their facilities, and Generation Owners did the same, duplicate monitoring may result. This isn't a problem as it pertains to the actual equipment monitored, but it potentially results in additional costs to the entities. Also, regardless of the NERC Functional Model definitions, there are many different actual equipment ownership arrangements between generation-only entities and the transmission entities to which they are connected. For example, a generation entity may or may not actually own the connection breakers in the transmission substation. We suggest throughout the standard that in all instances where a TO and/or GO "shall" do something, that the word "shall" be replaced with "shall ensure". This is the same wording used in the recently approved RFC DME standard PRC-002-RFC-01 which alleviated many stakeholder concerns regarding ownership and responsibilities for disturbance monitoring.2. The Compliance Section 1.5 of the standard includes information that is presently contained in requirement R4 of the existing PRC-002-1 standard. We have reviewed the NERC Reliability Standards Development Procedure and it appears that the SDT may have appropriately placed much of the section 1.5 information in section D. Compliance of the reliability standard. The only item in question is the second bullet of section 1.5.1 which may be more appropriately placed in the requirements section. However, it is FirstEnergy's opinion that "after the fact" data submittal type of requirements such as the need to "submit within 30 days upon request" are administrative, have no reliability impact and in general should not be subject to penalties and fines. While the inclusion of this item within the Compliance section avoids the item being subject to the Sanctions Guideline, we ask the team to reconsider its placement in the standard.It is FirstEnergy's opinion that the reliability standards need to evolve in such a way that clearly delineate reliability requirements from administrative requirements. We suggest subsections of section B "Requirements" labeled "1: Reliability Requirements" and "2: Administrative Requirements" and that the administrative requirements would generally receive "traffic ticket" warnings and only escalate to sanctions for repeat or willful violations.3. The Purpose statement of the standard is missing the "reporting" aspect of this standard. We suggest the SDT change the Purpose statement to match the Purpose of the current PRC-002-1 standard and also detailed in the SAR: "To establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models."4. The proposed Applicability section details the facilities for which the standard is applicable. However, since the proposed requirements already properly point out the locations that require disturbance monitoring equipment, the applicability section could simply state the TO and GO with no additional qualifying language.
Response:		
Florida Power & Light	No	

Organization	Yes or No	Question 16 Comment
Los Angeles Department of Water & Power	Yes	Final issue for LADWP is the proposed effective dates, 100% compliance within 4 years. Like many other utilities, our company is limited in resources, including design and installation staff. A preliminary review of these proposed regulations and their affect to our system suggests the need to install several new Fault Recorders and Disturbance Monitoring systems. The amount of work required will likely exceed the 4 years proposed. LADWP may need to discuss scenarios of extending installation dates beyong the proposed 4 year window.
Response:		
MRO NERC Standards Review Subcommittee	Yes	
PG&E System Protection	Yes	Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response:		
US Bureau of Reclamation	No	
NERC	Yes	Effective Date R12-R13For consistency, the first bullet under Effective Dates should read: The first day of the first calendar quarter two years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:"
Response:		
TransAlta	Yes	SDT took consideration of the resources needed when choosing the criterion for selecting locations for monitoring/recording disturbance data. This can be shown in Table 1 of R4, Each transmission line operated at 200 kV or above that does not have fault data recorded at its remote terminal. So if a line has fault data recorded at its remote terminal, it is not required to record at the nearest terminal. But what about the remote terminal is connected to a generator owned by a GO Does that mean the location owned by the TO is

Organization	Yes or No	Question 16 Comment
		excluded? If using this same approach, why cannot the terminal owned by a GO be excluded if the remote terminal has the fault data recorded? There are no such wordings in the requirements for GO's in the draft. So it is recommended that SDT review the disturbance monitoring/recording requirements at the location of interface between TO and GO.
Response:		
Grant County PUD		
NYISO	Yes	Section A5 first sentence: "The First Day of the first calendar quarter four years after?" I think "four" was meant to be "two" such that it's consistant with the end of the sentence.R1.1 I found the sentence difficult to understand, change to the wording in the table under R4.2R5.5 there is an extra "d" in "fault data recorded d at it's remote terminal"
Response:		
Tri-State Generation and Transmission Association	No	
Cowlitz County PUD	No	Typo above, it is 16.
Response:		
Portland General Electric	Yes	The following comments are those filed by the DMWG which we are filing in support: Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response:		
Progress Energy Florida	Yes	R1.1 and Table 4-1 specifies substations that "contain any combination of 3 or more transmission lines operated >200kV AND TRANSFORMERS having primary and secondary voltage ratings of >200kV".Above, the

Organization	Yes or No	Question 16 Comment
		words AND TRANSFORMERS is interpreted as the location must contain a transformer with primary and secondary voltages >200kV to be a required location. For example, as it's written this would mean the location needs to contain a 500/230kV transformer in addition to at least qty 2 - >200kV lines. A location with 5 >200kV lines and a non-qualifying 230/115kV transformer would not be a required location. If the word was OR a location with 3 >200kV lines would be a required location and would increase the 230kV substation requirement greatly. It is my opinion that these substations and associated >200kV lines do warrant monitoring because of their significance to the BES.R6.2 requires "16 samples per cycle", where R9.2 requires "960 samples per second". SDT should pick a common way to state sample rate. Table 4-1 the Location column specifies "transformers having primary AND secondary voltage ratings >= 200kV" where the Equipment column specifies "transformer having low-side operating voltage >= 200kV. Again, SDT should find a common way to state this requirement.
Response:		
Puget Sound Energy	Yes	Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response:		
Schneider Electric	Yes	The driver for this standard is to ensure that the data required for proper analysis is captured. In order to analyze events, data from multiple recorders and multiple locations will be required. Has the committee considered the differences in recording methods used between vendors and the resulting differences in data captured for the same event? Most countries specify IEC 61000-4-30 Class A devices to ensure that all devices (no matter the manufacturer or device type) will provide the same data for the same event. Has the committee considered this standard?
Response:		
Independent Electricity System Operator	Yes	R1 and R2 indicate the conditions under which SOE logging should be made, i.e. for changes in circuit breaker position. However, R4 and R5 as well as R7 and R8 do not say what the triggers for these recordings should be, e.g. a fault, a voltage sag or swell. We believe for consistency, reference should be made to some triggering

Organization	Yes or No	Question 16 Comment
		conditions or events.
Response:		
American Electric Power	Yes	AEP would suggest the addition of the following wording where appropriate: Per the requirements of this standard, the equipment owner is responsible for disturbance monitoring and reporting unless the Transmission and Generation Owners have an alternative agreement to monitor interconnecting equipment. Section 1.5 of the Section D should be moved into the technical requirement portion of the standard. These involve technical considerations. Please remove bullet three (related to interposing relays). The omission of "Measures" is of concern. A clear sight on measurement should be a part of requirement development, otherwise the objective will not be clear. Additionally, for Effective Date, Requirements R1 through R11, first bullet, first line, should state "two," not "four" years to be consistent. Under Requirements R12 and R13, first bullet, third line, "eighteen months" should be inserted after the word "quarter" and "NERC" should be inserted before "Board." To be clear, R4.2 (p. 6) should have "one winding of each monitored" added before the word "transformer" in line 2. Page 7 contains a typographical error in the fourth row of table 5-1, in the first bullet of column two has a "d" following "recorded" in the fourth line. The page 2 Future Development Plan, on item 7, should have "NERC" added before "Board." "NERC" should also be added before "Board of Trustees" in three locations in Section A-5.
Response:		
NextEra Energy Resources (formerly FPL Energy)	No	
National Grid		
Manitoba Hydro	No	
Exelon Generation LLC	Yes	1. Effective date: What does 50% compliant means for a registered Generation Owner (GO) like Exelon that has multiple sites with each site consisting of a single or multiple units? In our case, some units may require DDRs while others may not. Does 50% compliance within two years means 50% of the units in the fleet have to be compliant within two years or does 50% compliant within two years means 50% of the required parameters/quantities to be monitored should be available within two years? We are trying to understand for Generation Owners, does 50% compliance apply to a unit or to a site or to registered GO as a whole? Please clarify. 2. Effective date: PRC-018-1 had a Requirement of 75% compliant within 3 years. Has that Requirement been dropped by PRC-002-2- 3. Effective date: Requirement R12 and R13 This needs to be

Organization	Yes or No	Question 16 Comment
		clarified that these effective dates are applicable to the already installed DME equipment for which GO/TO is taking or intends to take credit for meeting the requirements of this standard. These dates are not applicable to the new equipment. New equipment is allowed to be installed within 2 to 4 years of Regulatory approval. So installing synchronizing capability within 18 months of Regulatory approval, when equipment is not even installed yet, does not make sense.
Response:		
NV Energy	No	
DTE Energy/Detroit Edison	Yes	When will violation severity levels be added?
Response:		
Wisconsin Electric	No	
ITC Transmission, METC	No	
City of Tallahassee (TAL)	Yes	R10; Delete the reference to R9 to read "Each TO and GO that installs a DDR device after January 1, 2011 to meet R7 and/or R8 shall install a device that is capable of continuous recording." R9 is a data management requirement only. It is not used to require the installation of a device. OR combine R10 into R9. R10 is an additional technical specification that would put the specs in one requirement, even though it would be a sub-requirement. Reiterate the need to move Section D Compliance items D.1.3.1, 1.3.2, 1.5.1 back into the requirements section.
Response:		
PHI (PEPCO Holdings Inc.)	No	
NV Energy (fka Sierra Pacific Resources)	No	
Salt River Project		
Pacific Northwest National	Yes	16A. My primary concern is that the proposed Standard does not address data quality issues, or establish a lexicon for such a discussion. Tedious as they may seem, filtering and spectral content are essential

Organization	Yes or No	Question 16 Comment
Laboratory		performance factors to examine in any DDR [21].16B. I have a LOT of concerns about Compliance item 1.5.1. The .dst files presently used in PMU networks are efficient to the point of being elegant--how large would an equivalent COMTRADE file be 16C. Item 1.5.1 should have an additional bullet on configuration files: All reported DDR data shall be accompanied by a configuration file (CF) providing the following primary information: [143] - the data source to which the CF applies (name of the archiving device) - structure of the data source records (number of sensors, sensor names, number of signals for each sensor) - parameters for each signal: ~ sensor producing the signal (includes sensor model & firmware version) ~ signal type (voltage, current, other) ~ scale factors for conversion to engineering units ~ timing shift or phasor rotation needed to correct known offset ~ associated voltage signal (for current signals only) ~ text data for generating signal name (might include sensor model & firmware version)It is acceptable to embed the configuratin file within the data header, if any.16D. Item 1.5.1 should have an additional bullet specifying a processing log to accompany data which have been changed from those initially recorded. Such changes might include filtering, resampling, calculation of derived quantities, renaming or selective deletion of signals.[143] Integrated Monitor Facilities for the Eastern Interconnection: Management & Analysis of WAMS Data Following a Major System Event, J. F. Hauer. Working Note of the Eastern Interconnection Phasor Project (EIPP), December 16, 2004.
Response:		
Progress Energy Carolina, Inc.	Yes	R6.2 requires "16 samples per cycle"R9.2 requires "960 samples per second "SDT should pick a common way to state sample rate.
Response:		
Hydro-Québec TransEnergie (HQT)	Yes	Regarding Table 2-1: Generator Owner's Requirement R2 for Sequence of Events Data, as we commented in Question 5 and elsewhere performance based stability studies have identified facilities operated at voltages below 200kV, generators with less than 500MVA capacity, aggregate plants with less than 1500MVA that when lost would have a significant impact on the power system. We do not feel that the 200kV threshold, nor the plant/plants' capacities are appropriate criteria for assessing criticality. This should be reflected in the table. The Applicability Section refers to Transmission Owners with facilities greater than 200kV, and Generator Owners with plants connected at greater than 200kV, capacities greater than 500MVA, aggregate plants with capacities greater than 1500MVA. As we commented in Question 5 and elsewhere we do not feel that the 200kV threshold is an appropriate criteria for assessing criticality, nor the single or generating plant capacity specifications.
Response:		

Organization	Yes or No	Question 16 Comment
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	Yes	Seems like Section D.1.5 Additional Compliance Information should be listed as part of the requirements.
Response:		
Northeast Utilities	Yes	The Applicability Section refers to Transmission Owners with facilities greater than 200kV, and Generator Owners with plants connected at greater than 200kV, capacities greater than 500MVA, aggregate plants with capacities greater than 1500MVA. As commented in Question 4, the 200kV threshold is an not an appropriate criteria for assessing criticality.
Response:		
San Diego Gas and Electric Co.	Yes	How would this standard apply to a typical combined cycle plant where the total capability of the plant is above 500MVA, but each of the individual generators is not?
Response:		
New York Independent System Operator	Yes	(D1.5) The bullet items covering COMTRADE and COMNAMES seem to us to be Requirements, and it seems odd to find these items under Compliance Information. We suggest that, if these items remain in this position, there should be a corresponding Requirement.D.1.5 Common DDR files can be converted into COMTRADE and the purpose stated in COMTRADE for this conversion to a common format is that conversion is necessary to facilitate the exchange of such data between applications. D.1.5 The drafting team should be aware of several IEEE PSRC activities which are in process now, and will affect items covered in this Standard. These activities include the following:C37.111 COMTRADE revision Working Group H4C37.118 Synchrophasor Standard revision Working Group H11Channel Names and Instrument Names Working Group H10SOE Data Working Groups H5b (completed) and H16
Response:		
E.ON U.S.		

Organization	Yes or No	Question 16 Comment
Arizona Public Service Co.	No	
JEA	No	
Tucson Electric Power	Yes	Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response:		
Alberta Electric System Operator	Yes	
Beckwith Electric Co	No	
Duke Energy	Yes	Key Issue #6 listed on page 3 of the Comment Form states that compliance elements (VRFs, VSL, etc.) will be included in a later version of the standard. We strongly encourage the drafting team to include these in the next version issued for comments, because the inclusion of these elements is needed to refine the Requirements.
Response:		
CenterPoint Energy	Yes	This draft standard includes ambiguities, such as the time stamp for the SOE data for the change in circuit breaker position (open/close) for each circuit breaker in a substation. Requirement 3 indicates the time stamp shall be recorded to within four milliseconds of input received for the change in circuit breaker position (open/close) for each of its circuit breakers specified in Requirements R1 and R2. It is questionable of what is meant by within four milliseconds of input received for the change in circuit breaker position. For example, is this referring to monitoring of a circuit breaker 52a or 52b auxiliary contact or is something else intended such as circuit breaker main contact parting or closing (when load or fault current begins and ends).The compliance section includes several items that appear to be requirements, but are shown in the compliance section instead of in the requirements section. For example, all the data must be in a format in which COMTRADE software can be used to evaluate the data. As another example, item D.1.5.1 states All known delays in interposing relays shall be reported along with the SOE data. It is unnecessary and excessive to require such reporting of time delays that are insignificant and should already be taken into account within the accuracy specification.

Organization	Yes or No	Question 16 Comment
		CenterPoint Energy recommends removing items for the Compliance section that are truly requirements. Each item removed should be evaluated before including it as a requirement in this proposed standard. While previously referenced in response to Question 13, CenterPoint Energy is concerned this proposed standard does not sufficiently take into consideration common natural disaster situations. The FERC-approved NERC reliability standard FAC-003 for Vegetation Management does include allowances for situations resulting from natural disasters, such as tornados and hurricanes. This proposed standard does not address the enormous quantities of data and associated complications that arise in such situations. CenterPoint Energy recommends reviewing the various requirements and including appropriate allowances to address the expected operational issues that are encountered during and after natural disasters.
Response:		
Xcel Energy	Yes	All of the items in section 1.5 "Additional Compliance Information" of the Compliance section appear to be requirements. These are adding to the requirements in the standard and are not appropriate in this section. If the SDT feels these should be required (by virtue of using "shall"), then a new draft should be developed to include these as actual requirements of the standard. Additionally, the new draft should be posted for another comment period.
Response:		
Utility System Efficiencies, Inc.	Yes	Would this standard apply to a combined cycle plant where the total capability was above 500 MW (and less than 1500 MW) but each of the individual units were not greater than 500 MW. Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. I suggest allowing DST files as are used by entities within WECC. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.16C. Item 1.5.1 should have an additional bullet on configuration files: All reported DDR data shall be accompanied by a configuration file (CF) providing the following primary information: - the data source to which the CF applies (name of the archiving device) - structure of the data source records (number of sensors, sensor names, number of signals for each sensor) - parameters for each signal: ~ sensor producing the signal (includes sensor model & firmware version) ~ signal type (voltage, current, other) ~ scale factors for conversion to engineering units ~ timing shift or phasor rotation needed to correct known offset ~ associated voltage signal (for current signals only) ~ text data for generating signal name (might include sensor model & firmware version)It is acceptable to embed the configuration file within the data header, if any.16D. Item 1.5.1 should have an additional bullet specifying a processing log to accompany data which have been changed from those initially recorded. Such changes might include filtering,

Organization	Yes or No	Question 16 Comment
		resampling, calculation of derived quantities, renaming or selective deletion of signals.
Response:		
British Columbia Transmission Corporation	Yes	Under the compliance section, 1.5.1, DDR data shall be in a format able to be viewed by COMTRADE. COMTRADE cannot display common DDR data file formats. Suggest allowing DST files as are used by entities within WECC. The last bullet under 1.5.1 in the Compliance section requires all data file names to be in conformance with IEEE C37.232-2007. Standard DDR equipment does not save file names in this manner. Does this requirement for naming conventions pertain only to shared files. This appears to be adding requirements to the standard in the Additional Compliance Information section.
Response:		
Kansas City Power & Light	Yes	Section 1.3.2 and section 1.5 are in the format of requirements of response times and data format expectations. This is unusual for the Data Retention section. Normally the Data Retention section is targeted to the time required to retain information to demonstrate compliance. It is possible the data format expectations could be in the compliance section. Request the SDT consider whether these are more in line as requirements rather than data retention. Believe there is a potential error in the Effective Date in Section A, item 5, Effective Date. The first sentence states for requirements R1 - R11 must be 50% compliant four years after approval of NERC or FERC, whichever applies. Should this be two years?
Response:		
PNM	Yes	

General Questions

17. Do you agree with the implementation plan as proposed by the SDT? If no, provide a plan that would be acceptable to you and provide rationale.

Summary Consideration:

Organization	Yes or No	Question 17 Comment
Northeast Power Coordinating Council	No	Under the section Effective Dates for PRC-002-2 Requirements R1 through R11, the first section reads: "1. The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:" For consistency the latter should be changed to four years after Board of Trustees adoption. As written, the timelines are not only inconsistent, but two years is too aggressive a time frame for what is required, in particular considering that Board of Trustees adoption precedes regulatory approval.
Response:		
IRC Standards Review Committee	No	The Implementation schedule for R1 - R11 is not clear. It seems as if a logical schedule would be that all entities be 50% compliant within 2 years and 100% compliant within 4 years. Yet as written it seems to obligate non-regulated entities to be compliant within 2 years while regulated entities have 4 years. Similarly for R12 & R13, the schedule gives regulated entities 18 months to comply but only 3 months for non-regulated entities.
Response:		
SPP System Protection and Control Working Group	Yes	1) Please clarify the effective dates section stating when each entity needs to be 50% and 100% compliant respectively.
Response:		
Members of the WECC Disturbance Monitoring Work Group		The Effective date information is unclear for the 50% and 100% compliance requirements.

Organization	Yes or No	Question 17 Comment
Response:		
Southern Company - Transmission	Yes	Southern Company supports the comments submitted by the SERC PCS for this question.
Response:		
SERC Engineering Committee Planning Standards Subcommittee	Yes	
SERC Protection and Controls Sub-committee	Yes	There appears to be a typo on the first bullet under Requirements R5.1 "Effective Date" four years should be two years. Also a typo under Requirements R12 and R13 where "eighteen months" was left out in the second part of the sentence. This needs to be clarified.
Response:		
PacifiCorp	Yes	The time allowed in the draft standard appears acceptable.
Response:		
Dominion	Yes	We suggest revising the language in section 5 first bullet for R1 through R11 to read: The first day of the first calendar quarter two years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required each Responsible Entity shall be at least 50% compliant within two years and 100% compliant within four years. Correct a typo error on the first bullet under requirement R5.1 Effective Date four years should be two years. Correct an omission error under Requirements R12 and R13 where eighteen months was left out in the second part of the sentence.
Response:		
Bonneville Power Administration	No	It's too fast for a 3 year budget cycle entity.
Response:		
FirstEnergy	Yes	Although we agree with the implementation plan, there seems to be a typographical error in the 1st bullet under the "Effective Date" section 5 of the standard: "four years" should be changed to "two years".

Organization	Yes or No	Question 17 Comment
Response:		
Florida Power & Light	No	From an audit standpoint the statement Each Responsible Entity shall be at least 50% compliant on monitored equipment would seem to be very difficult standard to meet or defend during on audit. Perhaps a better yardstick could be developed for improved audit ability. The overall four year requirement for 100% compliance and 50% compliance in 2 years will place an extremely high burden on many companies especially with nuclear assets. Two years is not enough time to budget design and install a DME into a nuclear facility. How can 50% compliance be met in two years? As seen in the last two years, most manufacturers are unable to keep up with industry demand. Therefore, the ability of the DME manufactures to meet the manufacture volume requirements is also unknown. Six years overall time frame is much more realistic for an implementation plan. GPS equipment synchronization is possible for all existing DMEs that I am aware of; however, some testing indicates that not all equipment can internally use this signal and actually time stamp to the required accuracy. Perhaps for older equipment, the requirement for accurate GPS time synchronization would be sufficient for the purpose of this standard. Older equipment should be allowed to be used during the transitional period without risk of an audit finding for not meeting a +2 millisecond time accuracy requirement. If you have equipment that cannot meet the +_ 2 millisecond requirement, this may result in an unintended consequence that will force companies to remove equipment from their DME list. Older DME equipment do not provide for long term storage. Requiring retrieval or local storage is only possible if the need for data is known soon enough to download and store locally. This would put almost everyone at risk for an audit finding for missing data. One of the primary reasons for replacing DMEs may be due to the 10 day retrieve ability requirement. It seems that timing of this requirement puts the cart before the horse and would seem entirely unrealistic to implement this requirement before the equipment is in place to provide the storage function. Again, if you have equipment that cannot meet the +_ 2 millisecond requirement, this may result in an unintended consequence that will force companies to remove equipment from their DME list.
Response:		
Los Angeles Department of Water & Power		
MRO NERC Standards Review Subcommittee	Yes	
PG&E System Protection		The Effective date information is unclear for the 50% and 100% compliance requirements. Also, how would

Organization	Yes or No	Question 17 Comment
		this implementation plan affect the PRC-018 application?
Response:		
US Bureau of Reclamation	No	As I have mentioned in tems 2 & 5 above, generator capacities (500MVA/unit and 1500MVA/plant) are too large. This will not help over-all post-disturbance analysis. These values should be 20MVA/unit and 75MVA/plant.
Response:		
NERC	No	Effective Date R12-R13For consistency, the first bullet under Effective Dates should read:The first day of the first calendar quarter two years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:
Response:		
TransAlta		
Grant County PUD	Yes	
NYISO	Yes	
Tri-State Generation and Transmission Association	No	Effective dates for 50% and 100% compliance are given. The dates are the same unless no regulatory approval is required. Should the date for 50% compliance be two years after the "applicable Regulatory Approval" instead of also four years?
Response:		
Cowlitz County PUD	Yes	Question 17 Comments: This standard as written will not apply to Cowlitz and therefore will not present a burden.
Response:		

Organization	Yes or No	Question 17 Comment
Portland General Electric		The following comments are those filed by the DMWG which we are filing in support: The Effective date information is unclear for the 50% and 100% compliance requirements.
Response:		
Progress Energy Florida	Yes	
Puget Sound Energy		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response:		
Schneider Electric	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	No	The phased-in approach presented in the Implementation Plan for compliance seem to be unnecessarily restrictive. Issues such as obtaining outages, acquisition of equipment, &/or obtaining personnel necessary to install/replace recording equipment can be difficult and time consuming. It is recommended that rather than the phased-in approach, set a timeframe for completion at a more reasonable five (5) year level regardless of whether there is existing equipment or not.
Response:		
National Grid		
Manitoba Hydro	Yes	
Exelon Generation LLC	No	1. Effective date: What does 50% compliant means for a registered Generation Owner (GO) like Exelon that has multiple sites with each site consisting of a single or multiple units? In our case, some units may require DDRs while others may not. Does 50% compliance within two years means 50% of the units in the fleet have to be compliant within two years or does 50% compliant within two years means 50% of the required parameters/quantities to be monitored should be available within two years? We are trying to understand

Organization	Yes or No	Question 17 Comment
		for Generation Owners, does 50% compliance apply to a unit or to a site or to registered GO as a whole? Please clarify. 2. Effective date: PRC-018-1 had a Requirement of 75% compliant within 3 years. Has that Requirement been dropped by PRC-002-2-3. Effective date: Requirement R12 and R13 This needs to be clarified that these effective dates are applicable to the already installed DME equipment for which GO/TO is taking or intends to take credit for meeting the requirements of this standard. These dates are not applicable to the new equipment. New equipment is allowed to be installed within 2 to 4 years of Regulatory approval. So installing synchronizing capability within 18 months of Regulatory approval, when equipment is not even installed yet, does not make sense.
Response:		
NV Energy	Yes	
DTE Energy/Detroit Edison	No	DME installation at generating stations are dependent on outage schedules. Suggest increasing compliance requirements to 50% at three years and 100% at five years.
Response:		
Wisconsin Electric		
ITC Transmission, METC	No	In the effective dates for Requirements R1 through R11, the Item 1. time frame of "four years" contradicts the Item 2. time frame "two years".
Response:		
City of Tallahassee (TAL)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project		

Organization	Yes or No	Question 17 Comment
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	No	Some region requirements developed under current PRC-002-1 are closer to where NERC is moving than with other regions. Current PRC-018-1 is underway with TO & GO implementation to meet those region requirements today. For PEC, May 2009 is the first 50% effective date per PRC-018-1. PEC believes that under these circumstances that NERC should address this unique situation now and not wait until PRC-002-2 approval. Compliance related to PRC-018-1 should be deferred until approval of PRC-002-2.
Response:		
Hydro-Québec TransEnergie (HQT)	No	Under the section Effective Dates for PRC-002-2 Requirements R1 through R11, the first section reads: "1. The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:" For consistency the latter should be changed to four years after Board of Trustees adoption. As written, the timelines are not only inconsistent, but two years is too aggressive a time frame for what is required, in particular considering that Board of Trustees adoption precedes regulatory approval.
Response:		
Brazos Electric Power Cooperative, Inc.		
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	No	Under the section Effective Dates for PRC-002-2 Requirements R1 through R11, the first section reads: "1. The first day of the first calendar quarter four years after applicable Regulatory Approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter two years after Board of Trustees adoption:" Two years versus four years is inconsistent.
Response:		
San Diego Gas and Electric Co.	Yes	

Organization	Yes or No	Question 17 Comment
New York Independent System Operator		
E.ON U.S.		
Arizona Public Service Co.		
JEA	Yes	
Tucson Electric Power		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response:		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response:		
Beckwith Electric Co	Yes	
Duke Energy	Yes	Regarding the effective dates for Requirements R1 through R11, we question the effective date for 50% compliance - shouldn't it be something less than four years? Four years is the timeframe for 100% compliance.
Response:		
CenterPoint Energy		
Xcel Energy	No	Paragraph 1 of the Implementation Plan appears to be written incorrectly. It says that 50% of R1 - R11 have to be completed in 4 years for following regulatory approval but within 2 years after BOT approval where regulatory approval is not required. Paragraph 2 then says that 100% of R1 - R11 has to be completed in 4 years. We assume the intent is for 50% of R1-R11 to be completed in 2 years, following regulatory approval, not 4 years.
Response:		

Organization	Yes or No	Question 17 Comment
Utility System Efficiencies, Inc.		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response:		
British Columbia Transmission Corporation		
Kansas City Power & Light	Yes	
PNM		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response:		

General Questions

18. The standard is proposing a definition for "Substation" based on the IEEE definition. Do you agree that there is sufficient misunderstanding of this term to warrant a definition? If so, do you agree that the IEEE definition is the most appropriate definition?

Summary Consideration:

Organization	Yes or No	Question 18 Comment
Northeast Power Coordinating Council	Yes	We agree that "substation" needs a definition. However, "switching station" is being used in the industry to describe those "substations" that do not necessarily have transformers, do not directly supply load or serve as generation outlets, but are strictly transmission junction points. Suggested rewording of the IEEE definition as applied to this Standard: Substation - An enclosed assemblage of equipment, e.g. switches, circuit breakers, buses and/or transformers, under control of qualified persons, through which electric energy is passed for the purpose of switching or modifying its characteristics. With the preceding change in mind, then Table 4-1: Transmission Owner's Requirement R4 for Fault Recording Data would have to be modified accordingly.
Response:		
IRC Standards Review Committee	No	
SPP System Protection and Control Working Group	Yes	
Members of the WECC Disturbance Monitoring Work Group		
Southern Company - Transmission	Yes	Southern Company supports the proposed definition of "Substation."
Response:		
SERC Engineering Committee	No	There is not sufficient misunderstanding to warrant a definition.

Organization	Yes or No	Question 18 Comment
Planning Standards Subcommittee		
Response:		
SERC Protection and Controls Sub-committee	Yes	We agree with the IEEE definition.
Response:		
PacifiCorp	Yes	
Dominion	No	We do not believe that a definition is warranted. However, if one is deemed necessary we agree with the use of the IEEE definition.
Response:		
Bonneville Power Administration	Yes	Also supply the IEEC C37.111-1999 and C37.232-2007 referred to.
Response:		
FirstEnergy	Yes	
Florida Power & Light	No	The terms substation and "Aggregate plant total nameplate" for the purpose of this standard should be well defined due to the compliance/audit issues that a misunderstanding of these terms could bring for a TO and/or GO.
Response:		
Los Angeles Department of Water & Power	Yes	
MRO NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 18 Comment
PG&E System Protection		
US Bureau of Reclamation	No	This document should be clarified the meaning of "Interconnected System." Is it connection of TO and GO system? Is it junction point of Main-transmission system and sub-transmission system? etc.
Response:		
NERC	Yes	
TransAlta		
Grant County PUD	Yes	
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	Some definitions of substation require a transformer so the IEEE definition includes what might be considered a switchyard as well as of a substation.
Response:		
Cowlitz County PUD	Yes	
Portland General Electric		
Progress Energy Florida	No	Clarification is needed whether to include switching stations as part of the criteria (ie, will a 230kV facility with 5 - 230kV transmission lines without a transformer require a DFR?) Many interpret that a substation includes transformation otherwise the station is a switching station.
Response:		
Puget Sound Energy		
Schneider Electric	Yes	

Organization	Yes or No	Question 18 Comment
Independent Electricity System Operator	Yes	
American Electric Power	Yes	Yes, AEP agrees that there is sufficient misunderstanding. No, AEP does not agree that the IEEE definition is the most appropriate. The portion 'enclosed assemblage' is not clear enough to distinguish assets applicable to the standard. For example, distinct and separate busses, of differing voltage, that may be enclosed by a common fence.
Response:		
NextEra Energy Resources (formerly FPL Energy)	Yes	
National Grid		
Manitoba Hydro	Yes	We agree with the IEEE definition.
Response:		
Exelon Generation LLC	Yes	
NV Energy	Yes	
DTE Energy/Detroit Edison	Yes	A definition is warranted, but the IEEE definition doesn't cover all the configurations that exist.
Response:		
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	The definition does not work with the standard. There are station facilities with multiple switchyards that are not connected locally. This may cause inaccuracies when counting number of lines for a substation.
Response:		

Organization	Yes or No	Question 18 Comment
City of Tallahassee (TAL)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)		
Salt River Project		
Pacific Northwest National Laboratory		
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	We agree that "substation" needs a definition. However, "switching station" is being used in the industry to describe those "substations" that do not necessarily have transformers, do not directly supply load or serve as generation outlets, but are strictly transmission junction points. Suggested rewording of the IEEE definition as applied to this Standard: Substation - An enclosed assemblage of equipment, e.g. switches, circuit breakers, buses and/or transformers, under control of qualified persons, through which electric energy is passed for the purpose of switching or modfiying its characteristics. With the preceding change in mind, then Table 4-1: Transmission Owner's Requirement R4 for Fault Recording Data would have to be modified accordingly.
Response:		
Brazos Electric Power Cooperative, Inc.	Yes	
WECC		
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	We agree that "substation" needs a definition. However, "switching station" is being used in the industry to describe those "substations" that do not necessarily have transformers, do not directly supply load or serve as generation outlets, but are strictly transmission junction points. Suggested rewording of the IEEE definition as

Organization	Yes or No	Question 18 Comment
		applied to this Standard: Substation - An enclosed assemblage of equipment, e.g. switches, circuit breakers, buses and/or transformers, under control of qualified persons, through which electric energy is passed for the purpose of switching or modfiying its characteristics. With the preceding change in mind, then Table 4-1: Transmission Owner's Requirement R4 for Fault Recording Data would have to be modified accordingly.
Response:		
San Diego Gas and Electric Co.		
New York Independent System Operator	Yes	
E.ON U.S.		
Arizona Public Service Co.		
JEA	Yes	
Tucson Electric Power		
Alberta Electric System Operator	No	
Beckwith Electric Co	Yes	
Duke Energy	No	We agree with the IEEE definition. We don't think that there is sufficient misunderstanding to warrant a NERC definition.
Response:		
CenterPoint Energy		
Xcel Energy		We agree the IEEE definition is appropriate.
Response:		

Organization	Yes or No	Question 18 Comment
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		
Kansas City Power & Light	Yes	
PNM	Yes	

Disturbance Monitoring Webinar Project 2007-11
March 12, 2009 Notes

Question: This question is regarding SOE information in Table 2-1. The generating units the 500 MVA is concerning. The level should be lower for SOE.

Answer: The team spent days deliberating on voltage level and ultimately felt that there is a point of diminishing return and selected this point for the standard.

Question: Dynamic Disturbance Recording – Question on implementation and the applicability and locations. PRC-002-2 - the SDT has taken a different direction than previous standards in terms of location (PRC-002-1). Why did the team change direction and is the significance of DDR the same as DFR? Question regarding applicability – 18 months after regulatory approval is not sufficient for generators.

Answer: 18 months is only for R12 and R13. The implementation plan considers time for generators to comply.

Question: PRC-018 did not have DM equipment requirements. As a result of the proposed continent wide standard will a GO have to purchase equipment?

Answer: The answer is "yes". PRC-018 was supposed to be developed by the RRO and the team has not changes direction and certainly not imposed new requirements on GOs.

Question: The existing NERC standard applies to the RRO but now the team is proposing it apply to the GO and TOs. Why has the RRO been removed from the standard?

Answer: FERC identified fill in the blank standards and did not like the approach to defer to the RROs in these standards. The team heeded FERC's direction to eliminate the fill in the blank elements.

Question: Are you interested in manufactures that can provide equipment?

Answer: It's the TO and GOs that have to meet the requirements – those who are responsible to record the data would like to know who can use the equipment and it would be best to reach out to them. You also have to check the requirements and see if your equipment will comply with the requirements.

Question: PRC-002-2 refers to substations throughout the document. What about addressing a switching station that might only have 4 or 6 lines going out of it? Second part of the question is the standard applies to TOs and GOs but shouldn't it apply to a "higher" level entity?

Answer: Starting with the second question – the TOs and GOs are the responsible entities for providing the data and the Regional Entity is responsible for coordinating. The first question – the team considered switching stations…

Question: Might it be appropriate to have sub-divisions within the standard to better organize the requirements? Also, shouldn't the 200 kV threshold be lower as there are facilities at lower kV that require monitoring?

Answer: There are different groupings – requirements related to sequence of events and requirements related to DDR but the team received feedback from NERC staff to remove the sub-headings. Regarding the voltage threshold, the team looked at data and based the level on this data. The team is currently collecting more data to further solidify the threshold.

Question: R5.3 – "Neutral…." – Can you use residual to meet requirement?

Answer: Yes, you can use the residual. The team will consider revising the language in the standard to clarify this.

Question: The team needs to come up with the technical justification for MVA levels. For Requirement R2 "Each GO shall record" if its already installed at the transformer could the requirement be written such that if a TO has the equipment to record the data?

Answer: The team is still working on justifying the levels. If the TO has equipment recording capability then this is OK but ultimately the responsibility lies with the GO.

Question: Collected data – if there is no reference to a common naming convention then the analysis process itself would be hindered. Common naming convention is missing and should be added to the standard.

Answer: The standard does in fact propose data format and naming convention under additional compliance information.

Question: Does the standard care about the equipment?

Answer: Our focus is on functionality and we don't care what equipment is being used.

Question: Question on the regulatory approval date being FERC approval – not BOT approval.

Answer: Yes, regulatory approval refers to FERC approval not NERC BOT approval.

Question:
R7 total # of lines – 7 or more transmission lines connected at 200 or more KV – substations where you don't cover that number. Substation would need to have DDR. What station would be picked up for DDR stations?

Answer: 7 was agreed upon…the team will need to look into this more.

Question: R7 and DDrs – parallel lines – can you combine lines on DDRs or does it have to separate? They are double circuit lines with separate circuit breakers.
Answer: Treat them as separate lines so additional boxes will be needed

Question: Concern about the 200 kV with FERC and NERC discussions of 100 kV lines –

Answer: There was time spent on finding solutions on 100 kV and the team felt it was a lot of work and money.

Question: Can the GO facility contract out the work?

Answer: as long as the GO shows NERC they meet the requirement and a process is in place.

Question: Maintenance and testing requirements – is there a gap where there is no maintenance and testing requirements?

Answer: We will need to check with our NERC sources to make sure that these requirements will be captured in a standard.

Disturbance Monitoring Technical Paper

Author Goes Here (if applicable)

Table of Contents

Introduction..Error! Bookmark not defined.

Section 1 — Applicability to Transmission Facilities 200 kV and above and Applicability to Generator Facilities 500 MVA and above ....Error! Bookmark not defined.

Section 2 — Number of Elements at a Substation.........................Error! Bookmark not defined.

Section 3 — Data Selected to Analyze an Event ....Error! Bookmark not defined.

Section 4 —Monitoring Relay System Communication Channel Signals (Relay Targets)Error! Bookmark n

Section 5 —Top 100 Busses by Region ....Error! Bookmark not defined.

Section 6 —Major Event Analysis ....Error! Bookmark not defined.

Section 7 —Monitoring of Special Protection Systems and Remedial Action SchemesError! Bookmark not

Section 8 —Critical Clearing Times...Error! Bookmark not defined.

Section 9 —Stability...Error! Bookmark not defined.

Appendix A — ....Error! Bookmark not defined.

Applicability to Transmission Facilities 200 kV and Above

Rationale for Transmission Level

In developing the Disturbance data requirements the SDT decided to focus on transmission voltage levels of 200 kV and above generators 500 MVA and above and generating stations 1500 MVA and above based on expected impact to the interconnected system. It is the team's strong belief that application of requirements below these values will require significant additional resources, while adding little value. The team recommends that requirements, if any, below these thresholds should be based on local needs to be identified by Regional Entities, while working with respective Transmission Owners and Generator Owners.

Impact to the Grid Below 200 kV

INSERT examples of past events below 200kV that did not significantly impact the grid.

Applicability to Generator Facilities 500 MVA and above

Rationale for 500 MVA Level

In developing the Disturbance data requirements the SDT decided to focus on transmission voltage levels of 200 kV and above generators 500 MVA and above and generating stations 1500 MVA and above based on expected impact to the interconnected system. It is the team's strong belief that application of requirements below these values will require significant additional resources, while adding little value. The team recommends that requirements, if any, below these thresholds should be based on local needs to be identified by Regional Entities, while working with respective Transmission Owners and Generator Owners.

Impact to the Grid Below 500 MVA

INSERT examples of past events below 500 MVA that did not significantly impact the grid.

Number of Elements at a Substation

Definition of Substation Used in Standard

The standard drafting team used the following IEEE definition to be used in this standard: Substation - As defined by the IEEE C2-2002, (National Electric Safety Code) “An enclosed assemblage of equipment , e.g. switches, circuit breakers, buses and transformers, under control of qualified persons , through which electric energy is passed for the purpose of switching or modifying its characteristics.” As an example, if at a given location, there are three (3) 500 kV lines and four (4) 230 kV lines along with a 500-230 kV transformer, this is one substation with 7 lines above 200 kV.

Criterion Used for Locations

The criterion used by SDT in selecting locations for monitoring/recording Disturbance data is based on minimum number of elements (lines, transformers, etc.) or minimum amount of generation at the location. This approach facilitates the measurement of compliance to the requirements.

Data Selected to Analyze an Event

Rationale for Selected Data

Insert blurb about why the particular data was selected and if other data is available why collecting this other data is not needed to analyze the event.

Sequence of events, faults, dynamic disturbances

For each type of data (sequence of events, faults, dynamic disturbances) the requirements are arranged as follows:

a. Locations for recording or having a process to derive: 1) sequence of events; 2) faults; and 3) dynamic disturbance recording data;
b. Equipment to be monitored at above locations;
c. Specific quantities to be monitored for above equipment; and
d. Technical parameters to ensure adequate data to analyze a Disturbance

Top 100 Buses (Chuck and Felix)

Rationale for Selected Data

Insert blurb about why this information is important to the development of the draft standard and how it impacted the draft standard (examples of places in the standard that can be justified by this analysis)

Midwest and Southeastern US (Felix's email)

Due to economic, environmental and regulatory constraints, large interconnected power systems are required to intensively and effectively utilize existing generation and transmission, hence electric utilities operate power systems close to their transient stability limits. Transient stability in the form of rotor angle stability, voltage stability and low frequency inter-area oscillations is related to the effects of transmission line faults on generator synchronism [1].

Stability depends strongly upon the magnitude and location of a fault and to a lesser extent upon the initial state or operating condition of the system. The three-phase fault with is the most severe disturbance, since no power can be transmitted through a zero-impedance, three-phase fault. Some of the cases identified for transient stability analysis include [1, 2, 3]:

- Three phase line fault leading to a single transmission circuit outage.
- Three phase bus fault leading to the loss of a bus.
- Three phase bus faults leading to the loss of a generator.
- Fault leading to major line overloading and voltage contingencies.

The DM SDT conducted a survey of low impedance busses from electric utilities in the Southeastern USA and also the Mid-West. Shorts circuits on such low impedances buses and tripping of transmission circuits due to the operation of protective relays, leads to the rest of the system being connected through higher impedance, significantly weaker paths. This may lead to overloading and cascaded tripping of other transmission lines, resulting in a system-wide disturbance and instability of the interconnected system. The table below shows the voltage levels with short circuit capacity (SC/C) greater than 10 000 MVA:

kV Level	Total # of Buses	SC/C > 10,000 MVA
500	60	35
345	79	63
230	1033	223
220	5	3
138	1242	5
115	1699	6

The above table indicates that, out of 335 low impedance buses with SC/C greater than 10000 MVA, 321 (95.6%) are 230kV and above

Jeff Pond – to collect data for his area (NPCC and possibly Canada)

Navin – to collect data for AEP

Willy – to collect data for SPP

Richard F. – to collect data for West/WECC (has data for WAPA)

Chuck – working with ERCOT to collect data

Larry – to collect data for Alabama

Event Analysis (Navin and Tracy)

Impact of Event Analysis on Development of Standard

Insert blurb about why this information is important to the development of the draft standard and how it impacted the draft standard (examples of places in the standard that can be justified by this analysis)

Monitoring Special Protection Systems and Remedial Action Schemes (Richard/Felix/Chuck)

Insert blurb about why this information is important to the development of the draft standard and how it impacted the draft standard (examples of places in the standard that can be justified by this analysis)

Critical Clearing Times (Chuck)

Critical Clearing Times

Insert blurb about why this information is important to the development of the draft standard and how it impacted the draft standard (examples of places in the standard that can be justified by this analysis)

Stability (Felix)

Stability

Insert blurb about why this information is important to the development of the draft standard and how it impacted the draft standard (examples of places in the standard that can be justified by this analysis)

DIRECTIONS TO FRCC/FCG
THE TOWERS AT WESTSHORE
1408 N. Westshore Blvd., Suite 1002
Tampa, FL 33607-4512
(813) 289-5644

FROM TAMPA INTERNATIONAL AIRPORT

When leaving the airport, take the Spruce Street exit. This is immediately after the exit to Clearwater. Follow the exit around until you are on Spruce Street. Take the second right at Westshore Blvd.

Proceed south to 1408 N. Westshore (immediately past Laurel Street on the west side of the street). The FRCC/FCG offices are located in the back building, Suite 1002. Parking is available around the building and the garage rooftop.

FROM NORTH FLORIDA & FROM ACROSS THE STATE via I-275

Travel I-275 South to Tampa. Take the Westshore exit, which is immediately following the Lois Street exit. Go north on Westshore and past Cypress Street. Turn left into the parking lot at 1408 N. Westshore and proceed to the back building. FRCC is in Suite 1002. Parking is available around the building and the garage rooftop.

FROM ST. PETERSBURG

Travel 1-275 North to Tampa. After crossing the bridge, take the Kennedy Boulevard exit. Proceed on Kennedy Blvd. to the Westshore Blvd. intersection. Turn left onto Westshore Blvd. Proceed north on Westshore Blvd., crossing over the Cypress Street intersection. Turn left into the parking lot at 1408 N. Westshore and proceed to the back building. FRCC is in Suite 1002. Parking is available around the building and the garage rooftop.

FROM CLEARWATER

Travel across the Courtney Campbell Causeway. After crossing the bridge, take the Spruce Street exit and continue to Westshore Blvd. Turn right.

Proceed south to 1408 N. Westshore (immediately past Laurel Street on the west side of the street). The FRCC/FCG offices are located in the back building, Suite 1002. Parking is available around the building and the garage rooftop.

FROM MIAMI OR JUNO

Travel turnpike to highway 60. Get off at (YEE HAW Junction). Take 60 to Brandon, Fl. Stay on 60 into Tampa. 60 will turn into Kennedy Blvd. From Kennedy, turn north on Westshore Blvd. Continue north on Westshore and past Cypress Street. Turn left into the parking lot at 1408 N. Westshore and proceed to the back building. FRCC is in Suite 1002. Parking is available around the building and the garage rooftop.

List of Hotels in the Area

Hyatt Place*	Residence Inn Marriott
4811 W. Main Street	4312 Boy Scout Blvd.
(813) 282-1037	(813) 877-7988
CORPORATE RATE	
Courtyard by Marriott	Renaissance Tampa Hotel
3805 W. Cypress Street	International Plaza
(813) 874-0555	4200 Jim Walter Blvd.
	(813) 877-9200
Doubletree Hotel	
4500 W. Cypress	Sheraton Suites Tampa Airport
(813) 879-4800	4400 W. Cypress Street
	(813) 873-8675
Embassy Suites	
555 N. Westshore Blvd.	Springhill Suites Marriott
(813) 875-1555	4835 W. Cypress
	(813) 639-9600
Hampton Inn *	
4817 W. Laurel	Tampa Airport Marriott
(813) 287-0778	Tampa International Airport
CORPORATE RATE	(813) 879-5151
Hilton Garden Inn*	Tampa Marriott Westshore
Tampa Airport/Westshore	1001 N. Westshore Blvd.
5312 Avion Park	(813) 287-2555
(813) 289-2700	
CORPORATE RATE	The Westshore Hotel*
	1200 N. Westshore Blvd.
Quorum Hotel	(813) 282-3636
700 N. Westshore Blvd.	**CORPORATE RATE**
(813) 289-8200	

* **Corporate Rates – close to FRCC Offices – See Page 2 for details**

Hampton Inn

- Across the street from the FRCC offices. To obtain the corporate rate, call the hotel directly at (813) 287-0778 and ask for in-house reservations. Calling an 800 number will put you through to national reservations and you will not get the corporate rate.

- Corporate Rate for 2008 - $139.00

Hilton Garden Inn (Avion Park) – Tampa Airport/Westshore

- Shuttle service to the FRCC Offices (within 3 miles)
- Brand new hotel near airport and FRCC offices
- Corporate Rate for 2008 - $129.00 for Double Queen/Standard King

Hyatt Place

- Within walking distance of the FRCC offices.
- Corporate Rate - $159.00 – January 1 – May 3
  $149.00 – May 4 – December 31

Westshore Hotel

- Next door to the FRCC Offices
- Corporate Rate - $89.00 – Guestroom $199.00 – Spa Suite – January – March, 2008
  $69.00 – Guestroom $159.00 – Spa Suite – April – December, 2008