UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. ____________**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PRC-002-2

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TABLE OF CONTENTS

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard PRC-002-2 (Disturbance Monitoring and Reporting Requirements) (Exhibit A). NERC requests that the Commission approve the proposed Reliability Standard and find that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of: (i) the Implementation Plan for the proposed Reliability Standard (Exhibit B); (ii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibits A and F); and (iii) the retirement of Reliability Standards PRC-002-1 (Define Regional Disturbance Monitoring and Reporting Requirements)

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2014).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 Unless otherwise designated, capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary of Terms"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

and PRC-018-1 (Disturbance Monitoring Equipment Installation and Data Reporting) as listed in the Implementation Plan.

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of proposed Reliability Standard PRC-002-2, a summary of the development history (Exhibit G), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (Exhibit D). This petition also provides background on Recommendations No. 24 and No. 28 in the U.S.-Canada Power System Outage Task Force ("Task Force"), *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* ("Final Blackout Report") and how the proposed Reliability Standard implements these Task Force Recommendations.[7] The NERC Board of Trustees ("NERC Board") adopted proposed Reliability Standard PRC-002-2 on November 13, 2014.

I. <u>EXECUTIVE SUMMARY</u>

Proposed PRC-002-2 contains the Requirements necessary to facilitate the analysis of Disturbances on the Bulk-Power System. The proposed Reliability Standard defines what sequence of events ("SER") recording, fault recording ("FR"), and dynamic Disturbance recording ("DDR") data should be recorded and how it should be reported.

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[5] 18 C.F.R. § 39.5(a) (2014).

[6] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g,* Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[7] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (Apr. 2004), *available at* http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[8]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[9] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duties of certifying an Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[10] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-

[8] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2014), to allow the inclusion of more than two persons on the service list in this proceeding.

[9] 16 U.S.C. § 824o (2012).

[10] *Id.* § 824(b)(1).

approved Reliability Standards. Section 215(d)(5)[11] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[12] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[13] and Section 39.5(c)[14] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[15] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards

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[11] *Id.* § 824o(d)(5).

[12] 18 C.F.R. § 39.5(a).

[13] 16 U.S.C. § 824o(d)(2).

[14] 18 C.F.R. § 39.5(c)(1).

[15] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) ("Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.").

Development) of its Rules of Procedure and the NERC Standard Processes Manual.[16] In its order certifying NERC as the Commission's Electric Reliability Organization, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards[17] and thus satisfies certain of the criteria for approving Reliability Standards.[18] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and stakeholders must approve, and the NERC Board of Trustees must adopt a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. 2003 Blackout Report Recommendations No. 24 and No. 28

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout ("2003 Blackout").[19] The next day, the joint U.S.-Canada Task Force was established to investigate the causes of the blackout and how to reduce the possibility of future outages. The Task Force's work was divided into two phases as follows:

- Phase I: Investigate the outage to determine its causes and why it was not contained.
- Phase II: Develop recommendations to reduce the possibility of future outages and minimize the scope of any that occur.[20]

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16 The NERC *Rules of Procedure* are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

17 116 FERC ¶ 61,062 at P 250.

18 Order No. 672 at PP 268, 270.

19 U.S.-Canada Power System Outage Task Force, *Interim Report: Causes of the August 14th Blackout in the United States and Canada* at 1 (Nov. 2003) ("Interim Blackout Report"), *available at* http://emp.lbl.gov/sites/all/files/interim-rpt-Aug-14-blkout-03.pdf.

20 *Id.*

In November 2003, the Task Force issued the Interim Blackout Report, describing its investigation and findings and identifying the causes of the blackout.[21]

1. <u>NERC Board Recommendation 12 and 2003 Blackout Recommendation No. 28</u>

On February 10, 2004, after taking the findings of the Interim Blackout Report into account, the NERC Board approved a series of actions and strategic and technical initiatives intended to protect the reliability of the North American Bulk Electric System ("NERC Board Recommendations").[22] Among its actions, the NERC Board issued Recommendation 12 to install additional time-synchronized recording devices as needed and Recommendation 14 to improve system modeling data and data exchange practices.

NERC Board Recommendation 12a directed the reliability regions to define, within one year, regional criteria for the application of synchronized recording devices in power plants and substations. Regions were requested to facilitate the installation of an appropriate number, type and location of devices within the region as soon as practical to allow accurate recording of future system Disturbances and to facilitate benchmarking of simulation studies by comparison to actual Disturbances.[23] NERC Board Recommendation 12b directed facilities owners, in accordance with regional criteria, to upgrade existing dynamic recorders to include Global Positioning Satellite ("GPS") time synchronization and, as necessary, install additional dynamic recorders.[24]

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21 *Id.*

22 Minutes and agenda materials for the February 10, 2004 meeting of the NERC Board of Trustees are available at http://www.nerc.com/gov/bot/Pages/AgendasHighlightsMinutes.aspx. *See also* Final Blackout Report at Appendix D *NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, available at* http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.

23 NERC Board Actions at 207.

24 *Id*.

The Final Blackout Report, issued on April 5, 2004, verifies and expands the findings of the Interim Blackout Report. On certain subjects, the Task Force advocated for broader measures than those in the NERC Board Recommendations, including in Task Force Recommendation No. 28 to require use of time-synchronized data recorders.[25] The Task Force explained that a valuable lesson from the 2003 Blackout is the importance of having time-synchronized system data recorders. The Task Force noted that the investigation would have been significantly faster and easier if there had been wider use of synchronized data recording devices. The Task Force also stated that NERC Planning Standard I.F, Disturbance Monitoring, required the use of recording devices for Disturbance analysis.[26]

On the day of the blackout, time recorders were frequently used, but not synchronized to a time standard. The Task Force explained that, at a relatively modest cost, all digital fault recorders, digital event recorders, and power system Disturbance recorders can and should be time-stamped at the point of observation using a GPS synchronizing signal. The Task Force also explained that recording and time synchronization equipment should be monitored and calibrated to assure accuracy and reliability. The Task Force made the following four observations in Task Force Recommendation No. 28 to provide a broader approach than that proposed by the NERC Board:

> A. FERC and appropriate authorities in Canada should require the use of data recorders synchronized by signals from the Global Positioning System (GPS) on all categories of facilities whose data may be needed to investigate future system Disturbances, outages, or blackouts.
>
> B. NERC, reliability coordinators, control areas, and transmission owners should determine where high speed power system Disturbance recorders are needed on the system, and ensure that

[25] Final Blackout Report at 162.
[26] *Id*.

> they are installed by December 31, 2004.
>
> C. NERC should establish data recording protocols.
>
> D. FERC and appropriate authorities in Canada should ensure that the investments called for in this recommendation will be recoverable through transmission rates.

Following through on the Task Force Recommendation No. 28, NERC addressed items A, B, and C above through a single effort. The NERC Planning Committee's Interconnection Dynamics Working Group ("IDWG") examined NERC's Reliability Standards on Disturbance monitoring as well as existing interconnection-wide practices and concluded that the NERC Disturbance monitoring standards and related regional requirements were inadequate. The IDWG developed a set of recommendations for specific improvements in its final report, *Review of Regional Disturbance Monitoring Equipment*, which addresses both Recommendation 12 of the NERC Board Recommendations and the Task Force Recommendation No. 28.[27] The NERC Board adopted this report at its May 2005 meeting.[28] The report identified that the NERC Disturbance monitoring standards addressed only new equipment and:

(1) do not address time synchronization on existing installations;

(2) do not specify the process for identifying locations;

(3) do not specify the process for ensuring additional installations; and

(4) do not specify that dynamic recording devices or sequence-of-event recorders are necessary to meet Disturbance monitoring equipment requirements.[29]

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27 *See* NERC Planning Committee Mar. 16-17, 2005 Meeting, Agenda Item 6: IDWG Report at Att. A.

28 *See* NERC Board May 3, 2005 Meeting Complete Agenda Package, Agenda Item 11b: *Review of Regional Disturbance Monitoring Equipment – Recommendation 12a, available at* http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2005/BOT_Complete_Agenda_Package_0505.pdf.

29 *See* NERC Board May 3, 2005 Meeting, Item 11b IDWG Presentation on Review of Regional Disturbance Monitoring Equipment. This presentation is included in the Complete Agenda package

The report also identified that regional "Disturbance Monitoring" requirements and processes were deficient and inconsistent among the regions. These recommendations and input from the IDWG would translate into two Reliability Standards. Reliability Standard PRC-002-0 was revised and separated into two Reliability Standards—PRC-002-1 (Define Regional Disturbance Monitoring and Reporting Requirements) and PRC-018-1 (Disturbance Monitoring Equipment Installation and Data Reporting). In the Task Force's *Final Report on Implementation of Task Force Recommendations* ("Blackout Implementation Report"), the Task Force noted that completion and approval by applicable regulatory authorities in the United States and Canada of any standard was required to fully implement Task Force Recommendation 28.A, 28.B, and 28.C.[30]

2. <u>NERC Board Recommendation 14 and 2003 Blackout Recommendation No. 24</u>

The NERC Board Recommendations also included Recommendation 14 to improve system modeling data and data exchange practices. Recommendation 14 directs the regional reliability councils to establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance. The Recommendation also instructed that validated modeling data must be exchanged on an inter-regional basis as needed for reliable system planning and operation.

Task Force Recommendation No. 24 relates to improving the quality of system modeling data and data exchange practices. The Task Force states in Recommendation No. 24 that it strongly supports NERC Board Recommendation 14. The Task Force further recommended that

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[30] *See* Blackout Implementation Report at 37 (Sept. 2006), *available at* http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinalImplementationReport(2).pdf.

FERC and appropriate authorities in Canada require all generators, regardless of ownership, to collect and submit generator data to NERC, using a regulator-approved template. The Task Force noted that after-the-fact models developed to simulate the conditions and events in the blackout established that the dynamic modeling assumptions for generator and load power factors in regional planning and operating models were frequently inaccurate.

While NERC directly addressed Recommendation No. 24 through other standard development work, a mandatory and enforceable Reliability Standard for Disturbance monitoring further supports the implementation of this Trask Force Recommendation. The Task Force noted in the Blackout Implementation Report:

> …new [Board-approved] standards, along with standards previously approved by the NERC Board of Trustees in February 2005 as part of the "Version 0" standards, represent a comprehensive set of standards for steady-state and dynamics system data reporting, modeling and simulation, and model validation that address this recommendation.[31]

The Version 0 standards included PRC-002-0, which was not ultimately approved by the Commission, as noted in Section D below.

D. History of PRC-002 and PRC-018

On April 4, 2006, as modified on August 28, 2006, NERC submitted to the Commission a petition seeking approval of an initial set of 107 proposed Reliability Standards.[32] NERC included PRC-002-0 in its April 4th Petition. NERC replaced this version with PRC-002-1 and also submitted PRC-018-1 for Commission approval in its August 28th Petition.[33] Both requirements in the original version 0 standard were substantially revised and four new

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31 Blackout Implementation Report at 35.

32 *See* NERC Apr. 4, 2006 and Aug. 28, 2006 Petitions in FERC Docket No. RM06-16-000.

33 *See* NERC Aug. 28 2006 Petition *available at* http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/FERC_Filing_Proposed_Reliability_Standards_Docket_RM06-16-000.pdf.

requirements were added. PRC-002-1 requires the Regional Reliability Organizations to establish requirements for installation of Disturbance Monitoring Equipment and reporting of Disturbance data to facilitate analyses of events and verify system models. PRC-018-1 is designed to ensure that Disturbance Monitoring Equipment is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.

In Order No. 693, the Commission identified Reliability Standard PRC-002-1 as a "fill-in-the-blank" standard that should be modified to apply, through the Functional Model, to the users, owners and operators of the Bulk-Power System that are responsible for providing information.[34] As a result, the Commission decided not to approve or remand PRC-002-1.[35] The Commission agreed with various commenters to the *Notice of Proposed Rulemaking* preceding Order No. 693 that greater continent-wide consistency could be achieved in this Reliability Standard.[36] The Commission directed the ERO to consider the comments of the American Public Power Association, Alcoa, Inc., and Otter Tail Power Company as it modifies PRC-002-1 to provide missing information needed for the Commission to act on PRC-002.[37] These comments are provided in Exhibit E: *Consideration of Issues and Directives*. Generally, the comments called for revisions to PRC-002-1 to provide greater consistency in this Reliability Standard and a continent-wide approach.

In addition, the Commission approved PRC-018-1 as mandatory and enforceable.[38] In its determination and in light of the approval status of PRC-002-1, the Commission stated applicable entities were expected to comply with PRC-018-1, and the procedures specified in

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34 Order No. 693 at PP 77-78.
35 *Id.* at P 1455.
36 *Id.* at P 1456.
37 *Id*.
38 *Id*. at P 1551.

PRC-002-1 would be provided pursuant to the data gathering provisions of the ERO's Rules of Procedure and the Commission's ability to obtain information.[39]

E. History of Project 2007-11 Disturbance Monitoring

NERC initiated Project 2007-11 to address Commission concerns in Order No. 693, specifically the "fill in the blank" aspects in both Reliability Standards PRC-002-1 and PRC-018-1. A standard authorization request to initiate the project was initially posted in 2007 with a scope of reviewing both standards and merging them into one replacement standard. In 2010, the Standards Committee prioritized ongoing work, which resulted in moving Project 2007-11 to informal development status. In its 2013 work plan, the Standards Committee changed the status to "formal development" as part of the effort to address pending projects.

The standard drafting team revised the standard authorization request to focus the standard on creating a results-based approach to the capture of data , instead of prescriptive requirements on equipment necessary to capture the data. The standard drafting team also added the Reliability Coordinator and Planning Coordinator as applicable entities in the standard authorization request to allow the standard drafting team to assign responsibility for specifying and collecting needed dynamic Disturbance data.

IV. <u>JUSTIFICATION FOR APPROVAL</u>

As discussed in Exhibit D and below, the proposed Reliability Standard PRC-002-2, satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Proposed PRC-002-2 contains the Requirements necessary to facilitate the analysis of Disturbances on the Bulk-Power System.

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[39] *Id*. at P 1550.

The proposed Reliability Standard contains twelve Requirements, which collectively define what SER, FR, and DDR data should be recorded and how it should be reported.

The following section broadly describes Disturbance monitoring, explains the purpose of proposed Reliability Standard PRC-002-2, provides a description of and the technical basis for the requirements, and describes how the proposed Reliability Standard improves reliability as compared to prior versions. This section also provides a brief summary of how the proposed Reliability Standards satisfies the outstanding Commission directives from Order No. 693 related to PRC-002-1, fully implements Task Force Recommendation No. 28, and contributes to NERC's efforts to implement Task Force Recommendation No. 24. Finally, this section includes a discussion of the enforceability of the proposed Reliability Standard.

A. Disturbance Monitoring

The NERC Glossary defines a "Disturbance" as;

> 1. An unplanned event that produces an abnormal system condition.
>
> 2. Any perturbation to the electric system.
>
> 3. The unexpected change in [Area Control Error] that is caused by the sudden failure of generation or interruption of load.[40]

It is important that Disturbances are monitored and analyzed so that the Bulk-Power System may be planned and operated to avoid instability, separation and Cascading failures. As defined in the NERC Glossary, Disturbance Monitoring Equipment consists of devices capable of monitoring and recording system data pertaining to a Disturbance.[41] The definition includes various types of recorders. Sequence of event recorders record equipment response to the event.

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[40] NERC Glossary at 30.

[41] The definition also provides that "Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs."

This includes opening and closing of breakers and switches used to isolate faulted equipment. Fault recorders record actual waveform data replicating the system primary voltages and currents. This may include protective relays. Dynamic Disturbance recorders record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions.

Analysis of the data captured under the proposed Requirements of PRC-002-2 can be used to improve the accuracy of planning and operating models and to identify risks to the Bulk-Power System that might not have been previously identified. DDR data is needed to compare actual system performance with expected system performance under Disturbance conditions. The results of the comparison of actual system performance with expected system performance under Disturbance conditions allow engineers to improve system models that are used for both planning and operating the Bulk-Power System. For example, current, voltage and frequency waveforms for actual and expected system performance can be compared and revisions can be made to the model to have the simulated waveforms more closely match the actual waveforms under Disturbance conditions. These revised models result in more accurate planning studies and, result in more accurate contingency analysis performed in near real-time.

B. Proposed Reliability Standard PRC-002-2

1. Purpose of and Types of Data Covered in Proposed PRC-002-2

The purpose of proposed Reliability Standard PRC-002-2 is to have adequate data available to facilitate analysis of Bulk Electric System Disturbances. The proposed Reliability Standard focuses on ensuring that the requisite data is captured and the Requirements constitute a results-based approach to capturing data.[42] The proposed Reliability Standard consolidates the current PRC-002-1 Reliability Standard and pertinent requirements of PRC-018-1 and improves reliability by providing personnel with necessary data to enable more effective post event analysis. The collected information can also be used to verify system models.

The proposed Reliability Standard includes coverage for SER, FR, and DDR data. SER and FR data can be used for the analysis, reconstruction, and reporting of Disturbances. Knowing the exact time of a breaker change of state and the waveforms of current, voltage and frequency for individual circuits allows the precise reconstruction of events for both localized and wide-area Disturbances. Analyses of wide-area Disturbances often begin by evaluation of SER data to help determine the initiating event(s) and to follow the Disturbance propagation. The recording of breaker operations helps to determine the interruption of line flows at a particular bus. However, under the proposed Reliability Standard, SER and FR data is not universally required since data from each bus is not necessary to be able to conduct an adequate or thorough analysis of a Disturbance. FR data also augments SERs in evaluating circuit breaker operation.

DDR data, which is also addressed in proposed PRC-002-2, is used to determine the Bulk-Power System's electromechanical transient and post-transient response and to validate system model performance. DDR data location is typically based on studies which include angular, frequency, voltage, and oscillation stability factors. However, to adequately monitor the Bulk-Power System's dynamic response and to ensure sufficient data to determine Bulk-Power System performance, DDR data is required for key Elements in addition to a minimum

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[42] The original SAR for this proposed Reliability Standard was focused on requirements for the installation of the equipment necessary to capture Disturbance monitoring data. The standard drafting team felt it was best to describe the performance requirements (using a risk-based approach) rather than prescribing necessary equipment.

requirement of DDR coverage based on an entity's peak system demand. Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these generators during a Disturbance helps the analysis of large Disturbances. DDR data shows transient response to Bulk-Power System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

Entities responsible for the Requirements in proposed PRC-002-2 and an explanation of each Requirement are included below. Additional technical support for each of these sections is included in the *Guidelines and Technical Basis Section* of the proposed Reliability Standard in Exhibit A.

2. Applicable Entities

4. Applicability:

Functional Entities:

4.1 *The Responsible Entity is:*

- ***4.1.1*** *Eastern Interconnection – Planning Coordinator*
- ***4.1.2*** *ERCOT Interconnection – Planning Coordinator or Reliability Coordinator*
- ***4.1.3*** *Western Interconnection – Reliability Coordinator*
- ***4.1.4*** *Quebec Interconnection – Planning Coordinator or Reliability Coordinator*

4.2 *Transmission Owner*

4.3 *Generator Owner*

The proposed Reliability Standard applies to the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection. In the Eastern Interconnection, the Planning Coordinator is the responsible entity. In the Western Interconnection, the Reliability Coordinator is the responsible entity. In ERCOT and the Quebec Interconnections, either the Planning Coordinator or the Reliability Coordinator is the responsible entity. The proposed Reliability Standard also applies to Transmission Owners and Generator Owners.

The Planning Coordinator or the Reliability Coordinator, as applicable, has the best wide-area view of the Bulk Electric System and is most suited to be responsible for determining the Bulk Electric System Elements for which dynamic DDR data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate dynamic Disturbance recording data is available for those Bulk Electric System Elements selected.

Bulk Electric System buses where SER and FR data is necessary are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own Bulk Electric System Elements on those buses will have the responsibility for ensuring that adequate data is available.

3. Proposed Requirements

(1) Requirement R1

R1. *Each Transmission Owner shall*: *[Violation Risk Factor: Lower] [Time Horizon: Long- term Planning]*

1.1. *Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.*

1.2. *Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES*

Elements require SER data and/or FR data.

1.3. *Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.*

Requirement R1 requires Transmission Owners to identify BES buses for which SER and FR data is required, provide notification to other owners of BES Elements connected to those particular BES buses that SER and FR data is necessary, and re-evaluate all BES buses every five years. This information, taken collectively, will allow for analysis and reconstruction of Bulk Electric System events.

Sequence of events and fault recording data for the analysis, reconstruction, and reporting of Disturbances is important in order to be able to analyze the Disturbance. The exact time of a breaker change of state and the waveforms of current, voltage and current for individual circuits allows the precise reconstruction of events for both localized and wide-area Disturbances. Analyses of wide-area Disturbances often begin by evaluation of SER data to help determine the initiating event(s) and to follow the Disturbance propagation. The recording of breaker operations helps to determine the interruption of line flows at a particular bus. As a general principle, more quality data is better when performing Disturbance analysis. However, one-hundred percent coverage of all Elements is not practical, cost-effective, nor required for effective analysis of wide-area Disturbances. Selectivity in the required buses to monitor is important to identify key buses with breakers where crucial information is available when required to analyze a Disturbance. Selectivity will also avoid excessive overlap of coverage and avoid gaps in critical coverage. The selection should provide coverage of Elements that could propagate a Disturbance, but avoid mandating coverage of Elements that are more likely to be a casualty of a Disturbance rather than a cause. The selection should ultimately establish selection criteria to provide effective coverage in different regions of the continent.

Each Part of Requirement R1 is described separately below and identifies the methodology designed by the standard drafting team for proper selection.

(a) Part 1.1

Part 1.1 requires Transmission Owners to identify buses for which SER and FR data is required. Transmission Owners are identified as the applicable entity in this Requirement because Transmission Owners have the required tools, information, and working knowledge of their systems to best determine buses where SER and FR data is required. The Requirement also specifies a consistent methodology to identify those buses in *Attachment 1: Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data*.

Analysis and reconstruction of Disturbances requires SER and FR data from key buses. Attachment 1 provides a uniform methodology (Median Method) to identify those BES buses. Review of actual short circuit data received from the industry in response to the drafting team's data request (June 5, 2013 through July 5, 2013) showed a strong correlation between the available short circuit MVA at a transmission bus and its relative size and importance to the Bulk-Power System based on (i) its voltage level, (ii) the number of Transmission Lines and other Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. Buses with a large short circuit MVA level are Elements that have a significant effect on System reliability and performance. Conversely, buses with very low short circuit MVA levels seldom cause wide-area or Cascading Disturbances, so SER and FR data from those Elements are not as significant for Disturbance analysis. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Under proposed PRC-002-2, there are a minimum number of buses for which SER and FR data is required based on the short circuit level. With the objective of having sufficient data for Disturbance analysis, the drafting team developed the procedure in Attachment 1 that utilizes the maximum available calculated three-phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and system topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution (see Step 8 discussion below). A description of how the standard drafting team arrived at this approach is included in the Guidelines and Technical Basis of Requirement R1 in the proposed Reliability Standard. The method employed is voltage level independent, is likely to select buses near large generation centers, and is likely to select buses where delayed clearing can cause Cascading. It also selects buses directly correlated to the Universal Power Transfer equation, which means that lower line impedance leads to increased power flows and greater system impact.

Attachment 1 provides a process for determining buses that require FR and SER data. Attachment 1 also notes that, for this standard, a single bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.[43]

[43] *See* PRC-002-2, Attachment 1 at Step 1.

In Attachment 1, Transmission Owners are first required to determine a complete list of buses that they own. Next, Transmission Owners reduce this list to only those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. The standard drafting team chose the threshold MVA values based on engineering and operational experience from analyzing and reviewing the short circuit data received from industry in response to a data request issued during the standard development process. This analysis showed a strong correlation between the available short circuit MVA at a transmission bus and its relative size and importance to the Bulk-Power System. The correlation was based on: (i) voltage level; (ii) the number of Transmission Lines and other Elements connected to the bus; and (iii) the number and size of generating units connected to the bus. Buses with a large short circuit MVA level significantly affect system reliability and performance, while buses with very low short circuit MVA levels are not as significant.[44] As a result, the standard drafting team included the narrowing of the buses covered by the standard based on the stated MVA value in Attachment 1, Step 2.

In Step 3, Transmission Owners must determine the eleven BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. The standard drafting team chose eleven BES buses because, in the judgment of the drafting team, a sufficient number of buses is necessary to accomplish the data coverage being sought for Disturbance analysis. Because the methodology stipulated the use of the median or middle value, eleven is used to provide five buses above and five buses below the median. In Step 4, Transmission Owners calculate the median MVA level of the eleven BES buses from Step 3, and in Step 5, determine a value that is twenty percent of this median MVA level from Step 4. The purpose of

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[44] BES buses with very low short circuit MVA levels seldom cause wide-area or Cascading System Disturbances.

this calculation is to provide a more narrowed scope for larger Transmission Owners that might have a large number of buses with a three-phase short circuit MVA level at 1500 MVA or above. This limits the number of buses for FR and SER data required under the standard for such entities while still providing adequate data for Disturbance analysis.

Step 6 again requires Transmission Owners to reduce the list to only those that have a maximum available calculated three-phase short circuit MVA higher than the greater of either 1,500 MVA or twenty percent of the median MVA level determined in Step 5.

Finally, Step 7 begins to identify the necessary buses. If there are no buses on the list by Step 7, the procedure is complete and no FR and SER data will be required. If the list has one or more but less than or equal to eleven buses, FR and SER data is required at the bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. If the list has more than eleven BES buses, SER and FR data is required on at least 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three-phase short circuit MVA.

To assure that adequate numbers of buses are included for collection of SER and FR data, Step 8 requires SER and FR data at additional buses from the list determined in Step 6. The aggregate of the number of buses determined in Step 7 and buses included through Step 8 must be at least twenty percent of the BES buses determined in Step 6. The remaining locations needed to meet this test are selected at the Transmission Owner's discretion to provide maximum wide-area coverage for SER and FR data based on each Transmission Owner's unique System configuration. Attachment 1 recommends the following BES bus locations:

- Electrically distant buses or electrically distant from other DME devices;
- Voltage sensitive areas;
- Cohesive load and generation zones;
- BES buses with a relatively high number of incident Transmission circuits;

- BES buses with reactive power devices; and
- Major Facilities interconnecting outside the Transmission Owner's area.

These locations are derived from PRC-002-1 and were reviewed and confirmed for inclusion by the standard drafting team as valuable information to inform the selection of locations.

Step 9 finally explains that the applicable buses subject to Requirement R1 is the collective total from Steps 7 and 8.

(b) Part 1.2

Part 1.2 requires Transmission Owners to notify other owners of Elements connected to those buses, if any, within 90-calendar days of completion of Part 1.1, that those Elements require SER data and/or FR data. Notification is necessary because these buses may be owned by more than one entity. The ninety calendar-day notification period gives the Transmission Owners adequate time to make appropriate determinations and notifications.

(c) Part 1.3

Part 1.3 requires each Transmission Owner to re-evaluate the bus list by repeating the performance in Parts 1.1 and Parts 1.2 at least every five (5) calendar years to account for system changes. The standard drafting team determined that the five (5) calendar year re-evaluation of the list of identified Elements is a reasonable interval based on its experience with changes to the Bulk-Power System that may affect SER and FR data requirements.

(2) Requirement R2

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

Requirement R2 is intended to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each Element connected to a bus identified in Requirement R1. Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating Disturbance(s) and follow the Disturbance propagation throughout the Bulk-Power System. Recording of breaker operations helps to determine a timeline for status changes in circuit breaker positioning during a Disturbance. Generator Owners are included in this Requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's bus. Each breaker status change will be time stamped according to Requirement R10 to a time-synchronized clock.

(3) Requirement R3

R3. *Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1*: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 *Phase-to-neutral voltage for each phase of each specified BES bus.*

3.2 *Each phase current and the residual or neutral current for the following BES Elements:*

3.2.1 *Transformers that have a low-side operating voltage of 100kV or above.*

3.2.2 *Transmission Lines.*

Requirement R3 requires the Transmission Owner and Generator to have FR data to determine certain electrical quantities. In order to cover all possible fault types, all bus phase-to-neutral voltages are required to be determinable for each bus identified in Requirement R1. The required electrical quantities may be either directly measured or determinable if sufficient FR data is captured.[45] For Disturbance analysis, bus voltage data is sufficient. To distinguish between phase faults and ground faults, phase and residual currents are required. Furthermore, it

[45] *E.g.* residual or neutral current if the phase currents are directly measured.

allows Transmission Owners and Generator Owners to determine the location of the fault and the cause of relay operation(s).

For transformers operating with a low-side voltage of 100kV or above, the required data can come from either the high-side or low-side of the transformer. However, generator step-up transformers ("GSUs") and the leads connecting the GSU transformer(s) to the Transmission System that exclusively export energy directly from a generating unit or plant are excluded from Requirement R3 because the FR data on the transmission system captures the faults on the generator interconnection. The Generator Owners may install the FR data capability or contract with the Transmission Owners that already have suitable FR data for the provision of the data to determine the required electrical quantities.

(4) Requirement R4

R4. *Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 *A single record or multiple records that include:*

- *A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or*
- *At least two cycles of the pre-trigger data, the first three cycles of the post- trigger data, and the final cycle of the fault as seen by the fault recorder.*

4.2 *A minimum recording rate of 16 samples per cycle.*
4.3 *Trigger settings for at least the following:*

4.3.1 *Neutral (residual) overcurrent.*
4.3.2 *Phase undervoltage or overcurrent.*

Requirement R4 provides for time stamped pre- and post- trigger fault data that aids in analyzing system performance during fault conditions and determining whether the performance was as intended. System faults generally last for a short time period and having a 30-cycle total minimum record length is adequate to capture such data. The requirement allows an entity to provide multiple records. This allows time-synchronized legacy microprocessor relays to meet the requirement when the equipment is not capable of providing fault data in a single record of 30-contiguous cycles. Moreover, the minimum recording rate must be 16 samples per cycle (960 Hz) to get sufficient point and wave data for recreating accurate fault conditions.

(5) Requirement R5

R5. *Each Responsible Entity shall: [Violation Risk Factor: Lower] [Time Horizon: Long- term Planning]*

5.1 *Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:*

5.1.1 *Generating resource(s) with:*

5.1.1.1 *Gross individual nameplate rating greater than or equal to 500 MVA.*

5.1.1.2 *Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.*

5.1.2 *Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).*

5.1.3 *Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.*

5.1.4 *One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).*

5.1.5 *Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.*

5.2 *Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:*

5.2.1 *One BES Element; and*

5.2.2 *One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.*

5.3 *Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.*

5.4 *Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.*

Requirement R5 provides that each Responsible Entity will have DDR data for one Element and at least one additional Element per 3,000 MW of its historical simultaneous peak system demand. Furthermore, Requirement R5 ensures that there is adequate wide-area coverage of DDR data for specific Elements to facilitate accurate and efficient Disturbance analysis. Monitoring the Elements required for DDR data will facilitate thorough and informative Disturbance analysis of wide-area Disturbances on the Bulk-Power System.[46]

Ensuring that data for these Elements is captured significantly improves the accuracy of the analysis and understanding of why a Disturbance occurred, not simply what occurred. DDR plays a critical role in wide-area Disturbance analysis as it is used for capturing the transient and post-transient response. Such data is used for Disturbance analysis and for validating Bulk-Power System performance. Each Responsible Entity (Reliability Coordinator or Planning Coordinator) must ensure that there are sufficient Elements identified for DDR data capture because they have the best wide-area view of the system. Identifying the Elements requiring DDR data per Requirement R5 is based on industry experience with wide area Disturbance analysis and the need for adequate data to facilitate Disturbance analysis.

The standard drafting team decided that the five (5) calendar year re-evaluation of the list of identified Elements is a reasonable interval based on its experience with changes to the Bulk-Power System that may affect DDR data requirements. However, this standard does not preclude the Responsible Entity from performing this re-evaluation more frequently to capture

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[46] Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified Element in Requirement R5, part 5.1. Part 5.2 ensures wide-area coverage across all Responsible Entities.

updated Elements. Changes to the bulk power system do not mandate immediate inclusion of Elements into the in-force list, but the Elements must be re-evaluated at least every five (5) calendar years per Requirement R5, Part 5.4.

The Transmission Owners and Generator Owners whose Elements were selected must be notified to ensure that each Owner is aware of its responsibilities. The Responsible Entities (Planning Coordinator or Reliability Coordinator as applicable) must notify all Owners of the selected Elements that DDR data is required when requested per Requirement R5, Part 5.3. However, notification must only include the list of selected Elements that each Transmission Owner and Generator Owner respectively owns and not the entire list. Furthermore, the Responsible Entities must include the specific data for each Element in the notification.[47]

Each Transmission and Generator Owner is responsible for the provision of data for the Elements identified in Requirement R5 and subject to the conditions specified in Requirements R6-R11. The Implementation Plan allows each Transmission Owner and Generator owner to phase-in the data provision Requirements of the proposed Reliability Standard.

DDR data is only required for one end or terminal of the Elements that were selected, except for high-voltage, direct current circuits.[48] For an interconnection between two Responsible Entities, each must consider this interconnection independently and work together to determine how to monitor the Elements requiring DDR data. For an interconnection between two Transmission Owners or a Transmission Owner and a Generator Owner, the Responsible Entity must determine which entity will provide the DDR data and respectively notify the owners of such determination.

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[47] This data can either be directly measured or accurately calculated.

[48] For example, DDR data must be provided for at least one terminal of a Transmission Line or GSU transformer, but not both terminals.

(6) Requirement R6

R6. *Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- ***6.1*** *One phase-to-neutral or positive sequence voltage.*
- ***6.2*** *The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.*
- ***6.3*** *Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.*
- ***6.4*** *Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.*

Requirement R6 allows the Transmission Owner to determine (calculate, derive, etc.) the electrical quantities specified in Parts 6.1-6.4 for Disturbance analysis. DDR is used to measure transient response to system Disturbances during a relatively balanced post-fault condition. Providing a phase-to-neutral voltage or positive sequence voltage is sufficient to measure the transient response. Furthermore, since all of the buses within a particular location are at the same frequency, one frequency measurement is adequate.[49]

(7) Requirement R7

R7. *Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- ***7.1*** *One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.*
- ***7.2*** *The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.*
- ***7.3*** *Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current*

[49] The data requirements for proposed PRC-002-2 are based on a System configuration assuming that all normally closed circuit breakers on a BES bus are closed.

measurements are required.
7.4 *Frequency of at least one of the voltages in Requirement R7, Part 7.1.*

Requirement R7 ensures that generator data is available to determine the electrical quantities specified in Parts 7.1-7.4. A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Requiring Generator Owners to have DDR data at either the high or low-side of the GSU to determine the specified electrical quantities to adequately capture generator responses is necessary for the analysis of a Disturbance. Each Generator Owner is responsible for providing the necessary DDR data and may contract with the Transmission Owners that already have suitable DDR data for provision of such data.

(8) Requirement R8

R8. *Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 *Triggered record lengths of at least three minutes.*

8.2 *At least one of the following three triggers:*

- *Off nominal frequency trigger set at:*

	Low	*High*
o *Eastern Interconnection*	*<59.75 Hz*	*>61.0 Hz*
o *Western Interconnection*	*<59.55 Hz*	*>61.0 Hz*
o *ERCOT Interconnection*	*<59.35 Hz*	*>61.0 Hz*
o *Hydro-Quebec Interconnection*	*<58.55 Hz*	*>61.5 Hz*

- *Rate of change of frequency trigger set at:*

o *Eastern Interconnection*	*< -0.03125 Hz/sec*	*> 0.125 Hz/sec*
o *Western Interconnection*	*< -0.05625 Hz/sec*	*> 0.125 Hz/sec*
o *ERCOT Interconnection*	*< -0.08125 Hz/sec*	*> 0.125 Hz/sec*

o *Hydro-Quebec Interconnection*	*< -0.18125 Hz/sec*	*> 0.1875 Hz/sec*

- *Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.*

Requirement R8 ensures that DDR data is available on a continuous basis so that pre- and post-contingency timeframes can be analyzed. This continuous recording of data allows analysis for the evolving sequence of events that occur over an extended period of time, which may lead to large-scale system outages. DDR data is essential to this analysis process. Providing available data pre and post-contingency helps identify the causes and effects of each event leading to the outages. Continuously recording and storing such data is necessary to ensure that sufficient data is available for the entire Disturbance. Legacy DDR data recording equipment may not have the capability to record continuously. Therefore, to accommodate its use for the purpose of this standard, triggered records that meet the criteria of Parts 8.1 and 8.2 are acceptable if the equipment is installed prior to proposed PRC-002-2's effective date.[50]

(9) Requirement R9

R9. *Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 *Input sampling rate of at least 960 samples per second.*
9.2 *Output recording rate of electrical quantities of at least 30 times per second.*

Requirement R9 ensures consistency in DDR data sampling rates as well as the output recording rate. Using an input sampling rate of at least 960 samples per second (which

50 Frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery.

corresponds to 16 samples per cycle) on the input side of the DDR equipment ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency. Moreover, using an output rate recording rate of electrical quantities of at least 30 times per second provides these adequate recording speeds[51] to monitor low frequency oscillations during a Disturbance.

(10) Requirement R10

> ***R10.*** *Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
>
> *10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.*
> 10.2 *Synchronized device clock accuracy within ± 2 milliseconds of UTC.*

Requirement R10 ensures time synchronization of large volumes of geographically dispersed records from diverse recording sources critical to Disturbance monitoring. SER, FR and DDR data are required to be time-synchronized using the Coordinated Universal Time ("UTC") standard and formatted either with or without local time offsets. [52] The accuracy of the time synchronization applies only to the clock used by the monitoring equipment.[53] However, the time synchronization of the data itself is not required because of the inherent delays associated with measuring the electrical quantities (data) and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc.

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[51] An output-recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device.

[52] UTC is a recognized time standard that uses atomic clocks for generating precision time measurements. Local time offsets are expressed as a negative number (i.e. the difference between UTC and the local time zone where the measurements are recorded).

[53] The equipment used to measure the electrical quantities (FR, SER and DDR data) must be time synchronized to ± 2m/s accuracy.

Therefore, ensuring that the monitoring devices' internal clocks are within ± 2m/s accuracy is sufficient for time-synchronized data.

(11) Requirement R11

> ***R11.*** *Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
>
> ***11.1*** *Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.*
>
> ***11.2*** *Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.*
>
> ***11.3*** *SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.*
>
> ***11.4*** *FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.*
>
> ***11.5*** *Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.*

Requirement R11 standardizes formatting and naming of wide-area Disturbance data that significantly improves timely analysis.[54] Requirement R11 further provides for a reasonable time-period (30 calendar days) to collect data and perform any necessary calculations or formatting. Additionally, Requirement R11 provides for a practical time limit (10 calendar days) on the amount of time data must be stored and informs the requesting entities how long the data will be available. Retaining the data for any longer than 10 calendar days would be expensive and unnecessary. Any SER data recorded must be stored in simple ASCII.CSV format because

[54] Note that wide-area Disturbance analysis includes data recording from many devices and entities.

it will significantly improve data analysis for event records and enable using software tools to analyze SER data.[55] Part 11.4 provides for a well-established industry-standard formatting of FR and DDR data files,[56] while Part 11.5's standardized naming format provides for a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.[57]

(12) Requirement R12

> ***R12.*** *Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
>
> - *Restore the recording capability, or*
> - *Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.*

Requirement R12 ensures that all Transmission Owners and Generator Owners who own equipment used in collecting the required data have the ability to correct any failures and ensure the data is available for Disturbance analysis. However, an outage of the monitored Element does not constitute a failure of the Disturbance monitoring recording capability. Each Transmission and Generator Owner must restore recording capability within ninety calendar days. In the event the repairs cannot be made within 90 calendar days, the entity must develop a Corrective Action Plan ("CAP") for restoring the data recording capability.[58] The CAP timeline depends on the entity and type of data required.

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55 ASCII.CSV format is outlined in Attachment 2. Either equipment can provide the data in this format or a simple conversion program can be used to convert files into this format.

56 Part 11.4 provides standard format IEEE c37.111, which is the IEEE Standard for Common Format for Transient Exchange (COMTRADE) revision 1999 or later.

57 Part 11.5 uses the standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), used for providing Disturbance monitoring data.

58 An entity may not be able to restore the data recording capability for a variety of reasons, such as budget cycle, service crew availability, vendor availability, needing to order parts or equipment, needed outages, etc.

4. Improvements and Consideration of Commission Directives

Proposed PRC-002-2 improves upon Reliability Standards PRC-002-1 and PRC-018-1. Proposed PRC-002-2 creates a single, consolidated Disturbance monitoring Reliability Standard. Proposed PRC-002-2 also includes revisions to remove "fill-in-the-blank" aspects in both Reliability Standards in response to Order No. 693. The proposed Reliability Standard is no longer dependent on regional criteria to provide appropriate data. This creates greater consistently in the data recordation and will allow for data to be compared across the continent during analysis of Bulk-Power System Disturbances. The proposed Reliability Standard also provides a consistent, continent-wide approach to determining what data must be recorded for analysis of Disturbances in response to the Commission's determinations and commenter suggestions in Order No. 693.

The emphasis in proposed PRC-002-2 has shifted from the prior Reliability Standards to reflect what Bulk Electric System data is captured rather than on the method for how Disturbance monitoring data is captured. There are a variety of ways to capture the data proposed PRC-002-2 addresses, and existing and currently available equipment can meet the Requirements of this standard. As a result, the proposed Reliability Standard improves data capturing practices while providing efficiency in the approach taken by utilizing existing methods for data collection. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of data capture.

In some instances, the Requirements of the proposed Reliability Standard are prescriptive in their nature. For example, Requirement R10 specifies a time synchronization requirement of ± 2m/s accuracy and the use of UTC. Task Force Recommendation No. 28 specifically called for a requirement to have time-synchronized data. In order to meet this Recommendation, Requirement R10 was developed to ensure that both existing and future installations of recording capability could meet the time synchronization requirement. Other instances of prescriptive Requirements are necessary to ensure that the intent of Recommendation No. 28 is realized. The Recommendation also stated:

> The Task Force supports the intent of this requirement strongly, but it recommends a broader approach:
>
> A. FERC and appropriate authorities in Canada should require the use of data recorders synchronized by signals from the Global Positioning System (GPS) on all categories of facilities whose data may be needed to investigate future system Disturbances, outages, or blackouts.
>
> B. NERC, reliability coordinators, control areas, and transmission owners should determine where high speed power system Disturbance recorders are needed on the system, and ensure that they are installed by December 31, 2004.
>
> C. NERC should establish data recording protocols.

The standard drafting team took these recommendations into consideration when developing the proposed Reliability Standard. Specific data recording protocols were included to address the concerns stated in the Final Blackout Report including the importance of having time-synchronized system data recorders. As noted in the Final Blackout Report, "the Task Force's investigators labored over thousands of data items to determine the sequence of events, much like putting together small pieces of a very large puzzle."[59] This process could have been significantly faster and easier if there had been wider use of synchronized data recording devices.

In summary, Commission approval of this proposed Reliability Standard will meet the Commission directives in Order No. 693 and complete work to implement multiple Recommendations from the both the NERC Board and the Task Force. It will also improve

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[59] Final Blackout Report at 162.

analysis and modeling of Disturbances to assist in preventing future Disturbances in support of Task Force Recommendation No. 24 by including a version of PRC-002 in the NERC Reliability Standards that is mandatory and enforceable.

C. Enforceability of Proposed Reliability Standard

The proposed Reliability Standard PRC-002-2 includes Measures that support each Requirement to help ensure that the Requirements will be enforced in a clear, consistent, non-preferential manner and without prejudice to any party. The proposed Reliability Standard also includes VRFs and VSLs for each Requirement. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. A detailed analysis of the assignment of VRFs and the VSLs for proposed PRC-002-2 is included as Exhibit F.

V. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- the proposed Reliability Standard in Exhibit A;
- the other associated elements in the Reliability Standard in Exhibit A including the VRFs and VSLs (Exhibits A and F); and
- the Implementation Plan, including the noted retirements, included in Exhibit B.

Respectfully submitted,

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Date: December 15, 2014

Exhibit A

Proposed Reliability Standard PRC-002-2

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

    Functional Entities:

    4.1 The Responsible Entity is:

    4.1.1 Eastern Interconnection – Planning Coordinator

    4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator

    4.1.3 Western Interconnection – Reliability Coordinator

    4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator

    4.2 Transmission Owner

    4.3 Generator Owner

5. **Effective Dates:**

    See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

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

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Responsible Entity has dated evidence (electronic or hard copy) that each Transmission Owner or Generator

Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in

			than 90 percent of the data but less than 100 percent of the data in the proper data format.	than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RE (PC | RC)	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

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

Rationale for Functional Entities:

When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Responsible Entity has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Responsible Entity from performing this re-evaluation more frequently to capture updated BES Elements.

The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.

The Responsible Entity must notify all owners of the selected BES Elements that DDR data is required for this standard. The Responsible Entity is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Responsible Entity. Data for each BES Element as defined by the Responsible Entity must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Responsible Entities, each Responsible Entity will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Responsible Entities. It is intended that each Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-

calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses “what” data is recorded, not “how” it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
    - Electrically distant BES buses or electrically distant from other DME devices
    - Voltage sensitive areas
    - Cohesive load and generation zones
    - BES buses with a relatively high number of incident Transmission circuits
    - BES buses with reactive power devices
    - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES

Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Responsible Entity, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

A. Introduction

1. **Title:** ~~Define Regional~~ Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-~~1~~2

~~3. **Purpose:** Ensure that Regional Reliability Organizations establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of Disturbance data to facilitate analyses of events and verify system models.~~

3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.

4. **Applicability:**

~~Regional~~ Functional Entities:

4.1 The Responsible Entity is:

4.1.1 Eastern Interconnection – Planning Coordinator

4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator

~~**4.1.**~~ **4.1.3** Western Interconnection – Reliability ~~Organization.~~Coordinator

4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator

4.2 Transmission Owner

4.3 Generator Owner

~~5.~~ 5. **Effective** ~~Date: **Nine months after BOT adoption.**~~ **Dates:**

See Implementation Plan

B. Requirements and Measures

R1. ~~The Regional Reliability Organization~~Each Transmission Owner shall ~~establish the following installation requirements~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~**R1.**~~**1.1.** Identify BES buses for which sequence of ~~event~~events recording~~:~~ (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. ~~Location, monitoring and recording requirements~~Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

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

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~**R1.1.**~~**5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

- ~~Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).~~
- ~~Devices to be monitored.~~

~~**R2.** The Regional Reliability Organization shall establish the following installation requirements for fault recording:~~

~~**2.1.** Location, monitoring and recording requirements, including the following:~~

- ~~Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).~~

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements ~~to be monitored~~that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

~~P2.1.2.~~**M5.** The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Responsible Entity has dated evidence (electronic or hard copy) that each ~~location.~~Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

- ~~Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:~~

R6. ~~Three~~Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~R2.1.3.1.~~**6.1** One phase-~~-~~to-~~-~~neutral ~~voltages~~or positive sequence voltage.

~~2.1..2. Three phase currents and neutral currents.~~

~~2.1..3. Polarizing currents and voltages, if used.~~

~~2.1..4. Frequency.~~

~~2.1..5. Megawatts and megavars.~~

~~Technical requirements, including~~**6.2** The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

~~**R2.2.**~~**8.2** At least one of the following~~:~~ three triggers:

- ~~Recording duration requirements.~~

- ~~Minimum~~
  - Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of ~~16 samples per cycle.~~

~~Event triggering requirements.~~

~~**R2.** The Regional Reliability Organization shall establish the following installation requirements for dynamic Disturbance recording:~~

~~**2.2.** Location, monitoring and recording requirements including the following:~~

- ~~Criteria for equipment location giving consideration to the following:~~
  - ~~Site(s) in or near major load centers~~
  - ~~Site(s) in or near major generation clusters~~
  - ~~Site(s) in or near major voltage sensitive areas~~
  - ~~Site(s) on both sides of major transmission interfaces~~
  - ~~A major transmission junction~~
  - ~~Elements associated with Interconnection Reliability Operating Limits~~
  - ~~Major EHV interconnections between control areas~~
  - ~~Coordination with neighboring regions within the interconnection~~
- ~~Elements and number of phases to be monitored at each location.~~
- ~~Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:~~

~~**2.2..0.** Voltage, current and frequency.~~

~~**2.2..0.** Megawatts and megavars.~~

~~**2.2.** Technical requirements, including the following:~~

- ~~Capability for continuous recording for devices installed after January 1, 2009.~~

~~P3.2.2.Each device shall sample data at a rate of~~ at least 960 samples per second ~~and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.~~ .

~~The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following:~~

~~**3.0.** Criteria for events that require the collection of data from DMEs.~~

~~**3.0.** List of entities that must be provided with recorded Disturbance data.~~

~~**3.0.** Timetable for response to data request.~~

~~3.1. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE[1] analysis tool,~~

~~Naming of data files~~**9.2** Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

~~[1] IEEE C37.111-1999 IEEE Standard Common Format for Transient Data Exchange for Power Systems or its successor standard~~

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with ~~the IEEE~~ C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

~~R4.5.~~11.5 Data files will be named in conformance with C37.232 ~~Recommended Practice~~, IEEE Standard for Common Format for Naming Time Sequence Data Files[2]~~.~~ (COMNAME), revision C37.232-2011 or later.

~~3.2. Data content requirements and guidelines.~~

~~R3. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.~~

~~R3. The Regional Reliability Organization shall periodically (at least every five years) review, update and approve its Regional requirements for Disturbance monitoring and reporting.~~

~~D. Measures~~

~~M0. The Regional Reliability Organization's requirements for the installation of Disturbance Monitoring Equipment shall address Requirements 1 through 3.~~

~~M0. The Regional Reliability Organization's Disturbance monitoring data reporting requirements shall include all elements identified in Requirements 4.~~

~~M0. The Regional Reliability Organization shall have evidence it provided its Regional Disturbance monitoring and reporting requirements as required in Requirement 5.~~

~~M0. The Regional Reliability Organization shall have evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in Requirement 6.~~

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

~~[2] Compliance with this requirement is not effective until the IEEE Standard is approved.~~

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

As defined in the NERC~~.~~

~~1.2.~~ Rules of Procedure, "Compliance ~~**Monitoring Period and Reset Time Frame**~~

~~One calendar year.~~

~~**1.2. Data Retention**~~

~~The~~ Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability ~~Organization shall retain documentation of its DME requirements for three years~~Standards.

~~The Compliance Monitor will retain its audit data for three years.~~

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

~~The Regional Reliability Organization shall demonstrate compliance through providing its documentation of Disturbance Monitoring and Reporting requirements or self-certification as determined by the Compliance Monitor.~~

~~**2. Levels of Non-Compliance**~~

~~**2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exist:~~

~~**2.1.1** Disturbance data reporting requirements were not specified as required in R4.1 through R4.6.~~

~~**2.1.2** No evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in R6.~~

~~**2.2. Level 2:** There shall be a level two non-compliance if any of the following conditions exist:~~

~~**2.2.1** Technical requirements were not specified for one or more types of DMEs.~~

~~**2.2.2** Requirements do not provide criteria for equipment location or criteria for monitored elements or monitored quantities as required R1, R2 and R3.~~

~~**2.3. Level 3:** Not applicable.~~

~~**2.4. Level 4:** Disturbance monitoring and reporting requirements were not available or were not provided to Transmission Owners and Generator Owners.~~

~~D. Regional Differences~~

~~None identified.~~

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in

			than 90 percent of the data but less than 100 percent of the data in the proper data format.	than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[3]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[3] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

<table>
<tr><th>Requirement</th><th>Entity</th><th>Identify BES Buses</th><th>Notification</th><th>SER</th><th>FR</th><th>5 Year Re-evaluation</th></tr>
<tr><td>R1</td><td>TO</td><td>X</td><td>X</td><td>X</td><td>X</td><td>X</td></tr>
<tr><td>R2</td><td>TO | GO</td><td></td><td></td><td>X</td><td></td><td></td></tr>
<tr><td>R3</td><td>TO | GO</td><td></td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>R4</td><td>TO | GO</td><td></td><td></td><td></td><td>X</td><td></td></tr>
</table>

<table>
<tr><th>Requirement</th><th>Entity</th><th>Identify BES Elements</th><th>Notification</th><th>DDR</th><th>5 Year Re-evaluation</th></tr>
<tr><td>R5</td><td>RE (PC | RC)</td><td>X</td><td>X</td><td>X</td><td>X</td></tr>
<tr><td>R6</td><td>TO</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>R7</td><td>GO</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>R8</td><td>TO | GO</td><td></td><td></td><td>X</td><td></td></tr>
<tr><td>R9</td><td>TO | GO</td><td></td><td></td><td>X</td><td></td></tr>
</table>

<table>
<tr><th>Requirement</th><th>Entity</th><th>Time Synchronization</th><th>Provide SER, FR, DDR Data</th><th>SER, FR, DDR Availability</th></tr>
<tr><td>R10</td><td>TO | GO</td><td>X</td><td></td><td></td></tr>
<tr><td>R11</td><td>TO | GO</td><td></td><td>X</td><td></td></tr>
<tr><td>R12</td><td>TO | GO</td><td></td><td></td><td>X</td></tr>
</table>

Rationale:

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

Rationale for Functional Entities:

When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Responsible Entity has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Responsible Entity from performing this re-evaluation more frequently to capture updated BES Elements.

The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.

The Responsible Entity must notify all owners of the selected BES Elements that DDR data is required for this standard. The Responsible Entity is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Responsible Entity. Data for each BES Element as defined by the Responsible Entity must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Responsible Entities, each Responsible Entity will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Responsible Entities. It is intended that each Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and

post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.
Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
    a. Only tangible substation or switchyard buses are included.
    b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.

7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings
Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Responsible Entity, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Exhibit B

Implementation Plan

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2007-11 Disturbance Monitoring

Requested Approvals
- PRC-002-2 Disturbance Monitoring and Reporting Requirements

Requested Retirements
- PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements
- PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting

Prerequisite Approvals
- None

Applicable Entities
- Planning Coordinator
- Reliability Coordinator
- Transmission Owner
- Generator Owner

Revisions to Defined Terms in the NERC Glossary
- None

Background
The Implementation Plan reflects consideration of the following:

1. This standard reflects the need for data, rather than equipment, with the understanding that the data is collected from Disturbance Monitoring Equipment distributed across the BES.
2. A significant amount of sequence of events recording (SER), fault recording (FR), and dynamic Disturbance recording (DDR) capability already exists on the BES. The monitoring requirements in this standard align with industry practices. Therefore, many existing recordings can satisfy the Requirements and Implementation Plan put forth.
3. Fault MVA data is readily available or calculable by the Transmission Owners for the BES buses they own. Therefore, six (6) months is adequate time for generating the list of BES buses following the methodology described in Attachment 1 (for Requirement R1).

4. Responsible entities have the relevant data and information pertaining to the BES Elements requiring DDR and six (6) months is adequate time for working with any affected entities and generating the list of BES Elements.
5. The nine (9) month time period for R12 includes the six (6) month implementation for R1 and R5, and a three (3) month additional time period to make notifications. The nine (9) months for R12 implementation is reasonable for the contents of that requirement.
6. A total percentage of BES buses and BES Elements established in Requirements R1 and R5 respectively are used in the Implementation Plan since these lists are explicitly created and readily available. It is expected that many monitoring requirements will become compliant without significant changes to recording capability.
7. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities.
8. Implementation of Disturbance monitoring recording following changes to the system are addressed by following re-evaluation of the lists as per Requirement R1 and Requirement R5.
9. Implementing SER, FR, and DDR capability may require scheduled outages for both Transmission Owners and Generator Owners. Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant. Meanwhile, Transmission Owners probably will have more BES Elements requiring SER, FR, and DDR and may have to schedule outages across the system. The Implementation Plan takes scheduling outages into account.
10. An entity owning only one (1) identified BES bus, BES Element, or generating unit is allowed six (6) years for implementation to accommodate normal outage schedules.
11. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities.

General Considerations

Each Transmission Owner and Generator Owner subject to PRC-018-1 shall maintain the ability to provide Disturbance monitoring data using current methods required by PRC-018-1 until the entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. As required in PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting, Requirement R1, Parts 1.1 and 1.2, it is expected that the Transmission Owner and Generator Owner will have those functionalities with regard to their current Disturbance data.

Effective Date

The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard(s) for Retirement

PRC-002-1 Midnight of the day immediately prior to the effective date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Each Transmission Owner, and Generator Owner shall maintain documentation to demonstrate compliance with PRC-018-1 until that entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2 and shall be applicable to an entity's Disturbance monitoring and reporting activities not yet transitioned to PRC-002-2. PRC-018-1 will be retired following full implementation of PRC-002-2 as noted below.

PRC-018-1 Midnight of the day immediately prior to six (6) years after the effective date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for PRC-002-2 Requirements R1 and R5:

Entities shall be 100 percent compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirement R12:

Entities shall be 100 percent compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:

Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.

Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.

Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated the list.

Conforming Changes to Other Standards

Where conflicts between the continent-wide standard PRC-002-2 and a regional standard exist, entities should comply with PRC-002-2. Conflicts will be addressed in the appropriate regional standards development process.

- PRC-002-2 Requirement R3 stipulates data must be captured by FR to determine electrical quantities. PRC-002-NPCC-01 Requirement R3 stipulates the recording of those quantities.
- PRC-002-2 Requirement R5 stipulates the capture of DDR data for HVDC. PRC-002-NPCC-01 does not specify HVDC for DDR.
- PRC-002-2 Requirement R8 recognizes DDR that is not continuous, and includes triggering data for DDR that is not continuous. PRC-002-NPCC-01 stipulates that dynamic Disturbance recorders installed after that standard was approved have to be continuous, but does not address legacy devices.

Exhibit C

Mapping Document

Project 2007-11 – Disturbance Monitoring

PRC-002-2 – Disturbance Monitoring and Reporting Requirements

Mapping Document for PRC-018-1 to PRC-002-2 and PRC-002-1 to PRC-002-2

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that arise from the inherent differences between regional power systems. PRC-018-1 and PRC-002-1 deal with equipment, PRC-002-2 deals with recording. By specifying data instead of equipment, PRC-002-2 governs the practical capturing of abnormal event data on the BES.

PRC-018-1 Requirements reference PRC-002-1 which requires PRC-018-1 Requirements to be either retired or covered in PRC-002-2.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard **PRC-002 Requirements 1-3**) shall have DMEs installed that meet the following requirements:	**R10.** Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset. 10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1.1. Internal Clocks in DME devices shall be synchronized to **within 2 milliseconds** or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be **retrievable for ten calendar days**.	**R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded. **11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor. **11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2. **11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later. **11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.
Notes: PRC-018-1, Requirement R1 is covered in PRC-002-2, Requirements R10 and R11.	

<table>
<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td colspan="2">PRC-018-1 addresses the equipment used for Disturbance monitoring data recording, PRC-002-2 addresses the recorded data. Technological advances made in the types of equipment used to record power system data have made it more effective to direct PRC-002-2 at the recording, not the equipment. Time synchronization and having the data retrievable for 10 days are general parameters that facilitate data analysis. PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirement R11.</td></tr>
<tr><td>R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization’s installation requirements (reliability standard PRC-002 Requirements 1 through 3).

PRC-002-1
R1. The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:
R1.1. Location, monitoring and recording requirements, including the following:

R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).
R1.1.2. Devices to be monitored</td><td>R1. Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.
1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.
1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns</td></tr>
</table>

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1.Location, monitoring and recording requirements, including the following: R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars. R2.2.Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements. R3. The Regional Reliability Organization shall establish the following installation	connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **3.1** Phase-to-neutral voltage for each phase of each specified BES bus. **3.2** Each phase current and the residual or neutral current for the following BES Elements: **3.2.1** Transformers that have a low-side operating voltage of 100kV or above. **3.2.2** Transmission Lines. **R4.** Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder. **4.2** A minimum recording rate of 16 samples per cycle. **4.3** Trigger settings for at least the following: **4.3.1** Neutral (residual) overcurrent. **4.3.2** Phase undervoltage or overcurrent.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
requirements for **dynamic Disturbance recording**: R3.1. Location, monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following:	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	**5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the reevaluated list of BES Elements as per the Implementation Plan. R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **6.1** One phase-to-neutral or positive sequence voltage. **6.2** The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. **6.3** Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. **6.4** Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for wich it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up (GSU) transformer high-side or low-side voltage level. 7.2. The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	• Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meets the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-018-1, Requirement R2 and PRC-002-1 Requirements R1-R3 are covered in PRC-002-2, Requirements R1-R9. PRC-018-1, Requirement R2 references PRC-002-1 Requirements R1-R2. PRC-002-1, Requirements R1-R3 reference equipment installation requirements for FR, SER, and DDR. The technical parameters of PRC-002-2 pertain to the characteristics and content of the recordings that are needed to facilitate event analysis.	
R3. The Transmission Owner and Generator Owner shall	None.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region’s installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker,	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
disconnect status, alarms, etc. R3.8.Monitored electrical quantities, such as voltage, current, etc.	
Notes: PRC-018-1, Requirement R3 is not covered in PRC-002-2. PRC-018-1 Requirement R3 refers to equipment and therefore is not mapped to PRC-002-2 which deals with recorded data and not equipment.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R4. The Transmission Owner and Generator Owner shall each **provide Disturbance data** (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard **PRC-002 Requirement 4**). **PRC-002-1** R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool.	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
Notes: PRC-018-1, Requirement R4 references PRC-002-1 Requirement R4 which is covered is PRC-002-2, Requirement R11.	
R5. The Transmission Owner and Generator Owner shall each **archive all data** recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	Covered in the Compliance section **1.2 Evidence Retention** The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation: The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years. The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years. The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years. The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years. If a Transmission Owner, Generator Owner, or Responsible Entity (Planning Coordinator or Reliability Coordinator) is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.
Notes: PRC-018-1, Requirement R5 is covered in the PRC-002-2 Compliance section under Evidence Retention.	
R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	**R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the SER, FR or DDR data either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R6.1. Maintenance and testing intervals and their basis. R6.2. Summary of maintenance and testing procedures.	
Notes: PRC-018-1, Requirement R6 is covered in PRC-002-2, Requirement R12. PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R12 deals with the long term availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability.	

Standard PRC-002-1	Proposed Standard PRC-002-2
R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event recording**: R1.1. Location, monitoring and recording requirements, including the following:	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data;

Standard PRC-002-1	Proposed Standard PRC-002-2
R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored	1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified per Requirement R1 and associated with the BES Elements at those BES buses. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
Notes: PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirements R1-R2. (See PRC-018-1, Requirement R3 above for additional information.)	
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1. Location , monitoring and recording requirements, including the following:	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1;

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars.	1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements they own connected to the BES buses identified per Requirement R1: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 3.1 Phase-to-neutral voltage for each phase of each specified line or BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1. Transformers that have a low-side operating voltage of 100kV or above. 3.2.2. Transmission Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include:

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.2. Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements.	• A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault as seen by the fault recorder. **4.2.** A minimum recording rate of 16 samples per cycle. **4.3.** Trigger settings for at least the following: **4.3.1.** Neutral (residual) overcurrent. **4.3.2.** Phase undervoltage or overcurrent.
Notes: PRC-002-1, Requirement R2 is covered in PRC-002-2, Requirements R1, R2, R4, and R5.	
R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**: R3.1. Location , monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

Standard PRC-002-1	Proposed Standard PRC-002-2
consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored	**5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element **5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the reevaluated list of BES Elements as per the Implementation Plan. **R6.** Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notifications as identified in

Standard PRC-002-1	Proposed Standard PRC-002-2
element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. **R8.** Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified as per Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz

Standard PRC-002-1	Proposed Standard PRC-002-2
	o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meets the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-002-1, Requirement R3 is covered in PRC-002-2, Requirements R5-R6 and R8-R9.	
R4. The Regional Reliability Organization shall establish requirements for facility owners	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per

Standard PRC-002-1	Proposed Standard PRC-002-2
to **report Disturbance data recorded** by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool, 4.5. Naming of data files in conformance with the IEEE	Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

Standard PRC-002-1	Proposed Standard PRC-002-2
C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	
Notes: PRC-002-1, Requirement R4 is covered in PRC-002-2, Requirement R13.	
R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the reevaluated list of BES Elements as per the Implementation Plan.
Notes: PRC-002-1, Requirement R5 is covered in PRC-002-2, Requirements R2, R6-R7.	
R6. The Regional Reliability Organization shall periodically (**at least every five years**) review, update and approve its Regional requirements for Disturbance monitoring and reporting.	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the reevaluated list of BES Elements as per the Implementation Plan.
Notes: PRC-002-1, Requirement R6 is covered in PRC-002-2, Requirements R1 and R5.	

Exhibit D

Order No. 672 Criteria

Exhibit D
<u>Order No. 672 Criteria</u>

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.**[2]

The purpose of proposed Reliability Standard PRC-002-2 is to have adequate data available to facilitate analysis of Bulk Electric System Disturbances. The proposed Reliability Standard focuses on ensuring that the requisite data is captured and the Requirements reflect a results-based approach to capturing data, rather than on equipment necessary to capture the data. The proposed Reliability Standard consolidates the current PRC-002-1 Reliability Standard and pertinent Requirements of PRC-018-1 and improves reliability by providing personnel with

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

necessary data to enable more effective post event analysis. The collected information can also be used to verify system models.

The proposed Reliability Standard includes coverage for sequence of events ("SER") recording, fault recording ("FR"), and dynamic disturbance recording ("DDR") data. SER and FR data can be used for the analysis, reconstruction, and reporting of Disturbances. Knowing the exact time of a breaker change of state and the waveforms of current, voltage and frequency for individual circuits allows the precise reconstruction of events for both localized and wide-area Disturbances. Analyses of wide-area Disturbances often begin by evaluation of SER data to help determine the initiating event(s) and to follow the Disturbance propagation. The recording of breaker operations helps to determine the interruption of line flows at a particular bus. However, under the proposed Reliability Standard, SER and FR data is not required since data from each bus is not necessary to be able to conduct an adequate or thorough analysis of a Disturbance. FR data also augments SERs in evaluating circuit breaker operation. DDR data, which is also addressed in proposed PRC-002-2, is used to determine the Bulk-Power System's electromechanical transient and post-transient response and to validate system model performance.

Proposed PRC-002-2 contains a technically sound means for determining what data needs to be captured. NERC provides a detailed explanation of each Requirement in the Petition. Broadly, the emphasis in proposed PRC-002-2 has shifted from the prior Reliability Standards to reflect what Bulk Electric System data is captured rather than on the method and equipment for how Disturbance monitoring data is captured. A variety of ways exist to capture the data proposed PRC-002-2 addresses, and existing and currently available equipment can meet the Requirements of this standard. As a result, the proposed Reliability Standard improves data capturing practices while providing efficiency in the approach taken by utilizing existing methods for data collection. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of data capture.

2. **Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]**

The proposed Reliability Standard applies to the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection. In the Eastern Interconnection, the Planning Coordinator is the responsible entity. In the Western Interconnection, the Reliability Coordinator is the responsible entity. In ERCOT and the Quebec Interconnections, either the Planning Coordinator or the Reliability Coordinator is the responsible entity. The proposed Reliability Standard also applies to Transmission Owners and Generator Owners.

The Planning Coordinator or the Reliability Coordinator, as applicable, has the best wide-area view of the Bulk Electric System and is most suited to be responsible for determining the Bulk Electric System Elements for which dynamic DDR data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate dynamic Disturbance recording data is available for those Bulk Electric System Elements selected.

3. **A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]**

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignments of the severity levels for the VSLs are consistent with the corresponding Requirement and will ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, and support uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences. Justification and explanation of the VRFs and VSLs is included in Exhibit F.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]

The proposed Reliability Standard contains Measures that support the Requirements by clearly identifying what is required and how the Requirements will be measured for compliance. The Measures are listed after each of the Requirements of the proposed PRC-002-2 Reliability Standard and provide clarity on types of evidence to support each Requirement, which will allow the Requirements to be enforced in a consistent and non-preferential manner.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standard achieves its reliability goal effectively and efficiently in accordance with Order No. 672. As noted in Criteria 1 above, the proposed Reliability Standard improves data capturing practices while providing efficiency in the approach taken by utilizing

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[5] Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

[6] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

existing methods for data collection. The proposed Reliability Standard also provides a consistent, continent-wide methodology for determining what SER, FR, and DDR data entities must capture in order to analyze Disturbances on the Bulk-Power System.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]**

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. The standard drafting team continuously sought to meet industry concerns and continue to maintain essential elements in the proposed Reliability Standard to effectively meet the purpose statement of the proposed Reliability Standard. The standard drafting team conducted a data request of industry, hosted industry webinars, consulted with NERC Events Analysis staff, and reviewed the lessons of the 2003 Final Blackout Report to ensure that the proposed Reliability Standard satisfied the Task Force's Recommendation Nos. 24 and 28.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]**

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[7] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

[8] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model. The Northeast Power Coordinating Council's ("NPCC") regional Reliability Standard PRC-002-NPCC-01 (Disturbance Monitoring) was considered by the standard drafting team during development. The Implementation Plan notes specific Requirements that may need to be revised as a result of the final Requirements in proposed PRC-002-2. NPCC will open a standard development project to address any conflict or overlap between the two Reliability Standards. The Implementation Plan notes that where the two conflict, entities should comply with the proposed continent-wide Reliability Standard. The regional Reliability Standard requires Transmission Owners and Generator Owners to provide recording capability necessary to monitor the response of the Bulk-Power System to system Disturbances, including scheduled and unscheduled outages; requires each Reliability Coordinator to establish requirements for its area's DR needs; and establishes Disturbance data reporting requirements.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

Proposed Reliability Standard PRC-002-2 has no undue negative effect on competition and does not unreasonably restrict transmission or generation operation on the Bulk-Power System.

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model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The time for transition in the Implementation Plan is reasonable and has included a phased-in approach. A phased approach to implementation recognizes that progress will be made while attempting to minimize any significant impact to the entities during transition. Implementing SER, FR, and DDR capabilities may require scheduled outages for both Transmission Owners and Generator Owners. Generator Owners may have outage cycles of twenty-four months or more depending on the type and characteristics of the generating units or plant. Meanwhile, Transmission Owners probably will have more BES Elements requiring SER, FR, and DDR and may have to schedule outages across its system. The Implementation Plan takes scheduling outages into account in the timeframes set for the proposed Reliability Standard. Compliance with PRC-018-1 will continue throughout the phased-in implementation. According to the Implementation Plan, each Transmission Owner and Generator Owner subject to PRC-018-1 must maintain the ability to provide Disturbance monitoring data using current methods required by PRC-018-1 until the entity meets the requirements of PRC-002-2 in accordance with the Implementation Plan.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards.

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10 Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

11 Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

Exhibit G includes a summary of the standard development proceedings, and details the processes followed to develop the Reliability Standard. These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has not identified competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

Proposed PRC-002-2 requires certain Generator Owners to record data and provide it upon request. The location for recording data is determined by the Transmission Owner under Requirement R1 and by the Responsible Entity under Requirement R5. In most cases, in order for the recording data to function properly, the installation of this recording data capability would be on the Generator Owners' equipment. Some Generator Owners have expressed concern that they do not have an avenue to recover the cost associated with implementation of this standard and that they cannot successfully compete in the market with these increased costs. While NERC understands the concern, NERC does not have the authority to include a cost recovery mechanism in the proposed Reliability Standard. However, the standard drafting team

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[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[13] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

made every effort to design Requirements that provided flexibility in aspects of the proposed Reliability Standard, while maintaining the data coverage needed to adequately analyze Disturbances.

Exhibit E

Consideration of Issues and Directives

Consideration of Issues and Directives

Project 2007-11 Disturbance Monitoring

PRC-002-2 Disturbance Monitoring and Reporting Requirements

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
“For the reasons stated in the NOPR, the Commission will not approve or remand PRC-002-1.” “We agree with [American Public Power Association], Alcoa and Otter Tail that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards. Consistent with that goal, the Commission directs the ERO to consider APPA, Alcoa and Otter Tail’s suggestions in the Reliability Standards development process as it modifies PRC-002-1 to provide missing information needed for the Commission to act on this Reliability Standard.” (see below for American Public Power Association, Alcoa, and Otter Tail discussion)	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1455-56	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances. The use of recording and specifying recording data parameters, greater consistency is achieved in PRC-002-2.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in addressing the completion of this Reliability Standard."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1452	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances.
"Alcoa suggests that the ERO—instead of a Regional Entity—should define the requirements for DME and the type of report it generates. The requirements and equipment specifications should be consistent throughout North America. In addition, Alcoa suggests that the criteria for installation of such equipment should include the necessary monitoring and recording that contribute to analysis and enhance reliability."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1453	Determines the key locations for which Disturbance data must be recorded which eliminates the need for equipment requirements. PRC-002-2 specifies the storage requirements and recording format for the collected data to ensure continent-wide uniformity to expedite event analysis.
"Otter Tail suggests that PRC-002-1 should be developed on an Interconnection wide basis to ensure consistency and promote reliability of the Bulk-Power System."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards	PRC-002-2 will apply on a continent-wide basis.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
	for the Bulk-Power System (Issued March 16, 2007); Paragraph 1454	
"The Commission requires supplemental information for any Reliability Standard that currently requires a regional reliability organization to fill in missing criteria or procedures. Where important information has not yet been provided to us to enable us to complete our review, we are not in a position to approve or remand those Reliability Standards. Accordingly, we will not approve or remand such Reliability Standards until the ERO submits further information. Until such information is provided, compliance with fill-in-the-blank standards should continue on a voluntary basis, and the Commission considers compliance with such Reliability Standards to be a matter of good utility practice."	Fill-in-the-blank Consideration FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 297.	By addressing recording instead of equipment, the Drafting Team has produced a continent-wide standard to have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.

Exhibit F

Analysis of Violation Risk Factors and Violation Severity Levels

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2007-11 Disturbance Monitoring

VRF and VSL Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-002-2 – Disturbance Monitoring and Reporting Requirements.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines.

The Disturbance Monitoring and Reporting Requirements Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria –VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed VRF	**Lower**
NERC VRF Discussion	R1 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 establishes the list of Sequence of Events Recordings and Fault Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for establishing a list of BES bus locations for Sequence of Events Recording and Fault Recording using the selection procedure in Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish the list of BES bus locations for Sequence of Events Recording and Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to establish a list of BES bus locations for Sequence of Events Recording and Fault Recording and to review the list every 5-calendar years. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Lower VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80% but less than 100% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by 10-calendar days or less.
Proposed Moderate VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70% but less than or equal to 80% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.
Proposed High VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60% but less than or equal to 70% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Severe VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by greater than 30-calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R1	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 provides criteria for Sequence of Events Recording which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Sequence of Events Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Sequence of Events Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to establish criteria for Sequence of Events Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 80% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Moderate VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 70% but less than or equal to 80% of the total SER

VRF and VSL Justifications – PRC-002-2, R2	
	data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed High VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 60% but less than or equal to 70% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Severe VSL	Each Transmission or Generator Owner as directed by Requirement R2 for less than or equal to 50% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R3	
Proposed VRF	**Lower**
NERC VRF Discussion	R3 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70% but less than or equal to 80% of the total set of required electrical quantities, which is the product of the total number of monitored BES

VRF and VSL Justifications – PRC-002-2, R3	
	Elements and the number of specified electrical quantities per each Element.
Proposed High VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60% but less than or equal to 57% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R4	
Proposed VRF	**Lower**
NERC VRF Discussion	R4 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recordings selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data that meets more than 80% but less than 100% of the total recording properties as specified in Requirement R4.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data that meets more than 70% but less than or equal to 80% of the total recording properties as specified in Requirement R4.

VRF and VSL Justifications – PRC-002-2, R4	
Proposed High VSL	The Transmission Owner or Generator Owner had FR data that meets more than 60% but less than or equal to 70% of the total recording properties as specified in Requirement R4.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60% of the total recording properties as specified in Requirement R4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-002-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 establishes the list of Dynamic Disturbance Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for identifying BES Elements for Dynamic Disturbance Recording. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to identify BES Elements for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective which identifies BES Elements within specified criteria and to review the list every 5-calendar years. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Responsible Entity identified the Elements for which DDR data is required as directed by Requirement R5 for more than 80% but less than 100% of the required Elements included in Part 5.1. OR

VRF and VSL Justifications – PRC-002-2, R5	
	The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.
Proposed Moderate VSL	The Responsible Entity identified the Elements for which DDR is required as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required Elements included in Part 5.1. OR The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.
Proposed High VSL	The Responsible Entity identified the Elements for which DDR data is requires as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required Elements included in Part 5.1. OR The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.
Proposed Severe VSL	The Responsible Entity identified the Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60% of the required Elements included in Part 5.1. OR

VRF and VSL Justifications – PRC-002-2, R5	
	The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R6	
Proposed Lower VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R6	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R7	
Proposed VRF	**Lower**
NERC VRF Discussion	R7 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R7	
Proposed Lower VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70% but less than or equal to 80% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60% but less than or equal to 70% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R7	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R8	
Proposed VRF	**Lower**
NERC VRF Discussion	R8 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes the need for continuous data recording and storage for Dynamic Disturbance Recordings established in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R6. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R8	
Proposed Lower VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80% but less than 100% of the Elements they own as determined in Requirement R5.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70% but less than or equal to 80% of the Elements they own as determined in Requirement R5.
Proposed High VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 6% but less than or equal to 70% of the Elements they own as determined in Requirement R5.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the Elements they own as determined in Requirement R5.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R8	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R9	
Proposed VRF	**Lower**
NERC VRF Discussion	R9 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement established technical specifications for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish technical specifications for Dynamic Disturbance Recording selected in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective which is to establish technical specifications for Dynamic Disturbance Recording selected in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 80% but less than 100% of the total recording properties as specified in Requirement R9.

VRF and VSL Justifications – PRC-002-2, R9	
Proposed Moderate VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 70% but less than or equal to 80% of the total recording properties as specified in Requirement R9.
Proposed High VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 60% but less than or equal to 70% of the total recording properties as specified in Requirement R9.
Proposed Severe VSL	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60% of the total recording properties as specified in Requirement R9.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3- Consistency among Reliability Standards**

VRF and VSL Justifications – PRC-002-2, R9	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This requirement established technical specifications for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R10	
Proposed VRF	**Lower**
NERC VRF Discussion	R10 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires time synchronization of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations established in R1 and R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failures to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective which is to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90% but less than 100% of the bus

VRF and VSL Justifications – PRC-002-2, R10	
	locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed High VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R10	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R11	
Proposed VRF	**Lower**
NERC VRF Discussion	R11 is administrative in nature and a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 provides criteria around timelines for providing the data and the data format. This is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria on providing Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R11 contains only one objective which is to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data within the specified criteria. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-

VRF and VSL Justifications – PRC-002-2, R11	
	calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% but less than 100% in the proper data format.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% but less than or equal to 90% in the proper data format.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70% but less than or equal to 80% of the requested data. OR

VRF and VSL Justifications – PRC-002-2, R11	
	The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% but less than or equal to 80% in the proper data format.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% in the proper data format.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R11	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R12	
Proposed VRF	**Lower**
NERC VRF Discussion	R12 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 provides criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to follow the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective which is to establish criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action

VRF and VSL Justifications – PRC-002-2, R12	
	Plan to the Regional Entity more than 90-calendar days but less than 100-calendar days after discovery of the failure.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	Guideline 2a: The VSL assignment is for R12 is not binary.

VRF and VSL Justifications – PRC-002-2, R12	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and	Non CIP

VRF and VSL Justifications – PRC-002-2, R12	
implementation should account for their interdependence	

Exhibit G

Summary of Development History and Complete Record of Development

Exhibit G: Summary of Development History

The development record for proposed Reliability Standard PRC-002-2 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give “due weight” to the technical expertise of the ERO[1]. The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit **H**.

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request (“SAR”) for Project 2007-11 Disturbance Monitoring was posted for a 30-day Comment Period from March 22 through April 20, 2007.

B. First Posting

Proposed Reliability Standard PRC-002-2 was posted for a 45-day public comment period from February 2, 2009 to March 18, 2009. There were 62 sets of comments, including comments from more than 130 different individuals from over 70 companies, representing 8 of the 10 industry segments. The standard drafting team considered stakeholder comments regarding proposed Reliability Standard PRC-002-2 and suggested changes to the standard. However, the Project was moved back into informal development by the Standards Committee. Upon reinitiating formal development in

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

2013, the standard drafting team considered the suggest changes in its revisions to the proposed standard, but created a new version.

C. Revised SAR

A revised SAR was posted for a 30-day comment period from May 5, 2013 to June 3, 2013.

D. Informal Request for Information

To provide input to the standard drafting team on the design of the proposed standard, the standard drafting team posted an informal request for information is for a 30-day period from June 5, 2013 through July 5, 2013.

E. Second Posting

Proposed Reliability Standard PRC-002-2 was posted for a 45-day public comment period, including a 10-day ballot from November 1, 2013 to December 16, 2013. There were 76 sets of comments, including comments from approximately 205 different individuals from approximately 157 companies, representing all 10 industry segments. . The proposed Reliability Standard received a quorum of 82.25% and an approval of 43.29%. A summary consideration of the comments and the changes made to the draft are included in the Consideration of Comments for Draft 2 included in the complete development record

F. Third Posting

Proposed Reliability Standard PRC-002-2 was posted for an additional 45-day public comment period, including a 10-day ballot from May 9, 2014 and June 25, 2014. The proposed Reliability Standard received a quorum of 77.69% and an approval of 52.29%. A summary consideration of the comments and the changes made to the draft are included in the Consideration of Comments for Draft 3 included in the complete development record.

G. Fourth Posting

Proposed Reliability Standard PRC-002-2 was posted for an additional 45-day public comment period, including a 10-day ballot from September 5, 2014 and October 21, 2014. The proposed Reliability Standard received a quorum of 77.69% and an approval of 71.38%. A summary consideration of the comments and the non-substantive changes made to the draft are included in the Consideration of Comments for Draft 4 included in the complete development record.

H. Final Ballot

Proposed Reliability Standard PRC-002-2 was posted for a final 10-day ballot from October 28, 2014 and November 6, 2014. The proposed Reliability Standard received a quorum of 81.89% and an approval of 68.51%.

I. Board of Trustees Adoption

Proposed Reliability Standard PRC-002-2 was adopted by the NERC Board of Trustees on November 13, 2014.

Project 2007-11 Disturbance Monitoring

Status:
PRC-002-2 - Disturbance Monitoring and Reporting Requirements was adopted by the NERC Board of Trustees November 13, 2014 and is pending regulatory approval.

Background:
This project was initiated to address an existing “fill in the blank” standard. FERC did not approve or remand PRC-002-1 in Order 693 because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. FERC did approve PRC-018-1 in Order 693. Similar to PRC-002-1, PRC-018-1 contained Regional Reliability Organization requirements, but FERC stated that the requirements are clear enough to be enforced. This project intends to address FERC concerns in Order 693, specifically the “fill in the blank” aspects in both standards. A SAR to initiate the project was initially posted in 2007 with a scope of reviewing both standards and merging them into one replacement standard. A standard drafting team was appointed by the Standards Committee in 2007, who drafted PRC-002-2, which was posted for a 45-day formal comment period in early 2009. The standard was posted for initial comments during February and March of 2009. In 2010 the Standards Committee decided to prioritize its work, which resulted in moving Project 2007-11 Disturbance Monitoring to informal development. Responses to the comments for the 45-day formal posting were developed, but not posted because of the change to informal development. In its 2013 work plan, the Standards Committee changed the status to formal development as part of the effort to address pending projects.

The drafting team revised the SAR to focus the project on a results-based approach to the capture of data, instead of prescriptive requirements on equipment necessary to capture the data. The drafting team believed that it was best to describe the performance requirements (using a risk-based approach) rather than prescribing necessary equipment. Also, the Reliability Coordinator and Planning Coordinator were added as applicable entities to ensure that the responsibility for specifying and collecting needed disturbance data can be appropriately assigned. The revised SAR was approved by the Standards Committee on May 2, 2013 to be posted for a 30-day informal comment period.

Purpose / Industry Need:
To establish requirements for collection and reporting of disturbance data to facilitate analyses of events and verify system models. This project involves modifying two standards:

- PRC-002 — Define and Document Disturbance Monitoring and Equipment Requirements
- PRC-018 — Disturbance Monitoring Equipment Installation and Data

The project involves replacing "fill-in-the-blank" requirements currently assigned to the Regional Reliability Organization, with continent-wide requirements that are applicable to other functional entities. As envisioned, each region will supplement PRC-002 with a regional standard that includes additional requirements. The project also involves bringing the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure.

Draft	Action	Dates	Results	Consideration of Comments
Final Draft **PRC-002-2** Clean **(84)** | Redline to Last Posting **(85)** Implementation Plan **(86)** **Supporting Materials** Median Method Excel Workbook **(87)** (Note: For TO use with Requirement R1, Attachment 1)	Final Ballot Info>> **(94)** Vote>>	10/28/14 – 11/06/14 (Closed)	Summary>> **(95)** Ballot Results>> **(96)**	

PRC-002-1 **(88)** PRC-018-1 **(89)** Issues and Directives **(90)** **Mapping Document** Clean **(91)** | Redline to Last Posting **(92)** VRF/VSL Justification **(93)**				
PRC-002-2 Clean **(63)** | Redline to Last Posting **(64)** Implementation Plan Clean **(65)** | Redline to Last Posting **(66)** **Supporting Materials** Median Method Excel Workbook **(67)** (Note: For TO use with Requirement R1, Attachment 1) Unofficial comment form (Word) **(68)** PRC-002-1 **(69)** PRC-018-1 **(70)** Issues and Directives **(71)** Mapping Document Clean **(72)** | Redline to Last Posting **(73)** VRF/VSL Justification Clean **(74)** | Redline to Last Posting **(75)** Draft RSAW Clean | Redline	Additional Ballot and Non-Binding Poll Updated Info>> **(76)** Info>> **(77)** Vote>>	10/10/14 - 10/22/14 (Closed)	Summary>> **(79)** Ballot Results>> **(80)** Non-Binding Poll Results>> **(81)**	Consideration of Comments>> **(83)**
	Comment Period Info>> **(78)** Submit Comments>>	09/05/14 - 10/21/14 (Closed)	Comments Received>> **(82)**	
	Please send RSAW feedback to: RSAWfeedback@nerc.net	09/19/14 - 10/21/14 (Closed)		
Cost Effective Analysis Phase 2 Report				
PRC-002-2 Clean **(43)** | Redline to Last Posting **(44)**	Additional Ballot and Non-Binding Poll Updated Info>> **(55)** Info>> **(56)**	06/13/14 - 06/25/14(Closed)	Summary>> **(58)**	Consideration of Comments>> **(62)**

Median Method Excel Workbook **(45)** (Note: For TO use with Requirement R1, Attachment 1) Implementation Plan Clean **(46)** | Redline to Last Posting **(47)** **Supporting Materials** Unofficial comment form (Word) **(48)** PRC-002-1 **(49)** PRC-018-1 **(50)** Issues and Directives **(51)** Mapping Document **(52)** VRF/VSL Justification Clean **(53)** | Redline to Last Posting **(54)**	Vote>>		Ballot Results>> **(59)** Non-Binding Poll Results>> **(60)**	
	Comment Period Info>> **(57)** Submit Comments>>	05/09/14 - 06/25/14(closed)	Comments Received>> **(61)**	
	RSAW Please send RSAW Feedback to: RSAWfeedback@nerc.net	06/06/14 - 06/20/14 (closed)		
Cost Effective Analysis for PRC-002-2 **Draft 2** PRC-002-2 **Supporting Materials** Cost Effective Analysis Process (CEAP) Unofficial comment form (Word) Implementation Plan	Comment Period Info>> Submit Comments>>	01/09/14 – 02/07/14 (closed)		
Draft 2 PRC-002-2 **(27)** Median Method Excel Workbook **(28)** (Note: For TO use with Requirement R1, Attachment 1) Implementation Plan **(29)** **Supporting Materials** PRC-002-2 Unofficial comment form (Word) **(30)** PRC-002-1 **(31)**	Ballot and Non-Binding Poll Updated Info>> **(36)** Info>> **(37)** Vote>>	12/06/13-12/16/13 (closed)	Ballot Results>> **(39)** Non-binding Poll Results>> **(40)**	Consideration of Comments>> **(42)**
	Comment Period Info>> **(38)** Submit Comments>>	11/01/13-12/16/13 (closed)	Comments Received>> **(41)**	
	Join Ballot Pool>>	11/01/13-12/02/13 (closed)		

PRC-018-1 **(32)** Issues and Directives **(33)** Mapping Document **(34)** VRF/VSL Justification **(35)**				
Cost Effective Analysis Process (CEAP) Unofficial comment form (Word)	Submit Comments>>	11/01/13-12/02/13 (closed)		
Supporting Materials: Informal Request for Information Report **(24)** Informal Information Request Spreadsheet **(25)**	Informal Request for Information Info>> **(26)** Please submit your information to Barb Nutter (Note: Only Generator Owners and Transmission Owners Should Submit Information)	06/05/13 - 07/05/13 (closed)		
Revised SAR Clean **(18)** | Redline to Last Posted **(19)** Supporting Materials: Unofficial Comment Form (Word) **(20)**	Comment Period Info>> **(21)** (Updated 05/15/13) Submit Comments>>	05/03/13 - 06/03/13 (closed)	Comments Received>> **(22)**	Consideration of Comments>> **(23)**
Supporting Materials: Nomination Form (Word) **(16)**	Nomination Period Info>> **(17)** Submit Nomination>>	04/12/13 - 04/25/13 (closed)		
Draft 1 Standard for Disturbance Monitoring Posted for a 45-day Comment Period PRC-002-2 **(9)** **Supporting Materials:** Comment Form (Word) **(10)**	Comment Period Info>> **(13)** Submit Comments>>	2/2/2009 - 3/18/2009 (closed)	Comments Received>> **(14)**	Consideration of Comments>> **(15)**

Mapping Document (11) Implementation Plan (12)				
Nomination Period Open for Disturbance Monitoring Standard Drafting Team	Nomination Period Info>> (8) Submit Nomination>>	6/12/2007 - 6/25/2007 (closed)		
Final SAR Version 1 Clean (6) | Redline (7)				
Version 1 SAR for Disturbance Monitoring Posted for 30-day Comment Period March 22 through April 20, 2007 Draft SAR Version 1 (2)	Comment Period Info>> (3) Submit Comments>>	3/22/2007 - 4/20/2007 (closed)	Comments Received>> (4)	Consideration of Comments>> (5)
Nomination Period Open for Disturbance Monitoring SAR Drafting Team	Nomination Period Info>> (1)	3/9/2007 (closed)		

	Submit Nomination>>			

Maureen E. Long
Standards Process Manager

February 26, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement
Nomination Period Opens for SAR Drafting Team

The Standards Committee (SC) announces the following standards actions:

Nominations for Project 2007-11 — Disturbance Monitoring SAR Drafting Team (February 26–March 9, 2007)

The Standards Committee is seeking industry experts to serve on the Project 2007-11 — Disturbance Monitoring SAR Drafting Team. If you are interested in serving on this team, please complete this nomination form and return it to Richard Schneider (Richard.schneider@nerc.net) no later than March 9, 2007.

A draft SAR for Project 2007-11— Disturbance Monitoring has been appended to the nomination form to aid in the understanding of the work to be performed by this SAR drafting team (this SAR will be posted for public comment at a later date). The draft SAR calls for the modification of the following standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data

This project involves upgrading the overall quality of these two standards; eliminating some gaps in the requirements; eliminating some ambiguity; and eliminating some "fill-in-the-blank" components.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Standard Authorization Request Form

Title of Proposed Standard:	Disturbance Monitoring (Project 2007-11)
Request Date:	March 1, 2007

SAR Requester Information

Name:	Robert W. Millard on behalf of the Regional Reliability Standards Working Group	***SAR Type (Check one box.)***	
Company:	Reliability*First* Corporation	☐	New Standard
Telephone:	(708) 588-9886	☒	Revision to Existing Standard
Fax:	(330) 456-3648	☐	Withdrawal of Existing Standard
E-mail:	bob.millard@rfirst.org	☐	Urgent Action

Purpose *(Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.)*

To establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models.

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV Planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV Planning Measures. As the Electric Reliability Organization begins enforcing compliance with Reliability Standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable Reliability Standards. The Version 0 standards and the translation of Phase III & IV Planning Measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards, Phase III & IV standards, and recent updates were put in place as a temporary starting point to start-up the Electric Reliability Organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and Phase III & IV translations.

Industry Need *(Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)*

1. Provide an adequate level of reliability for the North American bulk power systems — ensure the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties — ensure

   (a) the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined,

   (b) the purpose, requirements, and measures are results-focused and unambiguous and

   (c) the consequences of violating the requirements are clear.
3. Consider comments received during the initial development of this set of standards and other comments received from ERO regulatory authorities and stakeholders as described in the Detailed Description section below.
4. Bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure as described in Attachment 1 below.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Brief Description *(Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)*

PRC-002 and PRC-018 were approved in 2006.

PRC-002 is one of four reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard. The standard drafting team (SDT) will review PRC-002 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to or contained with the disturbance monitoring program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

The SDT shall consider comments and issues as described in the Detailed Description section and Attachment 1 below for drafting and including other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders through the standards development procedure, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check all boxes that apply.)	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☐	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
Recognizing that reliability is an essential requirement of a robust North American economy:
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description *(Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)*

1. The SDT shall consider the following comments (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006),
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application, and
    - Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development).
    - Phase III & IV Standard Drafting Team
    - Violation Risk Factors Drafting Team

    PRC-002 Define and Document Disturbance Monitoring Equipment Requirements

    FERC NOPR

    - Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information related to the fill-in-the-blank aspects of this standard as further defined below under "Regional Fill-in-the-Blank Team Comments".

    FERC Staff Report

    - This standard designates RROs as the applicable entity. Staff is concerned about the appropriateness of RROs serving as the applicable entity in the new mandatory standards structure. These standards have been referred to as "fill-in-the-blank" standards (see comments under "Regional Fill-in-the-Blank Team Comments" below).

    Phase III/IV comments

    - There are no criteria that the RROs must use in specifying the process for identifying locations where DMEs are required (to be addressed when considering issues under "Regional Fill-in-the-Blank Team Comments" below).

    Violation Risk Factor Drafting Team Comments

    - R1 - This standard and all related sub requirements are after the fact data analysis.

    Regional Fill-in-the-Blank Team Comments

    - Determine what elements (if any) should be included in the North American standard and what elements should be included in the regional standards.
    - Development of regional standards needs to be coordinated with regional entities.
    - Regional entities should be notified to begin process for developing regional standards once the standard drafting team has determined what elements should be included in the continent-wide standard and what elements should be included in the regional standards.

    PRC-018 Disturbance Monitoring Equipment Installation and Data

    Violation Risk Factor Drafting Team Comments

    - R3.4, 3.5, 3.6, 3.7 – Requirements as written are ambiguous and need more clearly defined.

2. The SDT will bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure as described in Attachment 1 below.

3. The SDT should also consider any other issues that were not completely captured but were stated or referenced in the above materials.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Attachment 1

Excerpts from the *Reliability Standards Development Procedure Manual, Version 6* and the *ERO Rules of Procedure*:

(The drafting team will reference and follow, as appropriate, the following guidelines *(or later version as appropriate)* in determining what changes to make to the standards to bring them into conformance with these guidelines.)

Standard Review Guidelines

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language

Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality

Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements

In general, requirements for entities to have ‘capabilities’ (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to ‘maintain’ their capabilities.

Consistent Terminology

To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a ‘unique’ definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Mitigation Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.

- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. (‘Violation severity levels’ replace existing ‘levels of non-compliance.’) The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, ‘Regional Reliability Organization’ with ‘Regional Entity’

Fill-in-the-blank Requirements

Do not include any ‘fill-in-the-blank’ requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply.

If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, ‘Associated Documents’.

Functional Model Version 3

Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Maureen E. Long
Standards Process Manager

March 22, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Period Opens

The Standards Committee (SC) announces the following standards action:

SAR for Disturbance Monitoring (Project 2007-11) Posted for 30-day Comment Period March 22–April 20, 2007

The SAR for Project 2007-11 proposes modifying the following two standards:

- PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
- PRC-018 — Disturbance Monitoring Equipment Installation and Data

PRC-002 is one of four reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The modifications will consider issues raised by FERC and stakeholders about these standards, and will bring the standards into conformance with the *ERO Rules of Procedure* and the latest version of the *Reliability Standards Development Procedure.* Please use the comment form to provide comments on this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Comment Form — 1st Draft of SAR for Disturbance Monitoring Project 2007-11

Please use this form to submit comments on the proposed SAR for Disturbance Monitoring. Comments must be submitted by **April 20, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "DME SAR" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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E-mail:	edavis@entergy.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV measures. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

   We do not think there is a reliability-related need to revise PRC-002 and PRC-018. However, we do agree that it will be a worthwhile effort to revise the two standards to make them: enforceable by FERC, more compatable with each other, and to address FERC staff and FERC comments.

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments:

Comment Form — 1st Draft of SAR for Disturbance Monitoring
Project 2007-11

Please use this form to submit comments on the proposed SAR for Disturbance Monitoring. Comments must be submitted by **April 20, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "DME SAR" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
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Telephone:	512-248-3077
E-mail:	smyers@ercot.com

NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV measures. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: N/A

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments: No further comments at this time.

Please use this form to submit comments on the proposed SAR for Disturbance Monitoring. Comments must be submitted by **April 20, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "DME SAR" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Thomas Owens	
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: There are specific changes needed, but the general SAR process steps listed should identify needed changes. Details can be worked out during drafting of changes.

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR. Comments: No comments until first draft is posted.

Comment Form — 1st Draft of SAR for Disturbance Monitoring Project 2007-11

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
Dave Powell	ED Planning and Protection		

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The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: RFC is in the process of developing a Disturbance Monitoring Equipment standard based on NERC standards PRC-002 and PRC-018. The SAR requires the SDT to review PRC-002 and each of the current regional programs developed in accordance to that standard. The SAR should be revised to require the SDT to review and address the current regional programs developed in accordance to PRC-018.

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: It appears this question is worded incorrectly such that it requires an explanation for a "Yes" response rather than an explanation for a "No" response.

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments: Please revise the Brief Description to include any special considerations for PRC-018 similar to the special considerations for PRC-002. Perhaps the last paragraph is applicable to both PRC-002 and PRC-018 standards but it is not clear. For the Applicable Reliability Principles Table on page 4, boxes 5 and 7 should also be checked since they refer to system monitoring.

Please use this form to submit comments on the proposed SAR for Disturbance Monitoring. Comments must be submitted by **April 20, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "DME SAR" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Roger Champagne	
Organization:	Hydro-Québec TransÉnergie	
Telephone:	514 289-2211, X 2766	
E-mail:	champagne.roger.2@hydro.qc.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV measures. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

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   ☒ Yes

   ☐ No

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   ☐ Yes

   ☒ No

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   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Ron Falsetti		
Organization: IESO		
Telephone: 905-855-6187		
E-mail: ron.falsetti@ieso.ca		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
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☐ **SPP**	☐	7 — Large Electricity End Users
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

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1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments:

Comment Form — 1st Draft of SAR for Disturbance Monitoring Project 2007-11

Please use this form to submit comments on the proposed SAR for Disturbance Monitoring. Comments must be submitted by **April 20, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "DME SAR" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **SPP**	☐	7 — Large Electricity End Users
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	IRC Standards Review Committee
Lead Contact:	**Charles Yeung**
Contact Organization:	**SPP**
Contact Segment:	**2**
Contact Telephone:	**832-724-6142**
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Additional Member Name	Additional Member Organization	Region*	Segment*
Mike Calimano	NYISO	**NPCC**	2
Alicia Daugherty	PJM	**RFC**	2
Ron Falsetti	IESO	**NPCC**	2
Matt Goldberg	ISO-NE	**NPCC**	2
Brent Kingsford	CAISO	**WECC**	2
Anita Lee	AESO	**WECC**	2
Steve Myers	ERCOT	**ERCOT**	2
William Phillips	MISO	**RFC+MRO+SERC**	2

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
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The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

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The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments:
   The SDT should pose questions regarding:
   (1a) whether or not NERC should require data recording performance requirements that can only be met by purchasing specific assets

   (1b) if it is sufficient to mandate what information and performance is required rather than the hardware itself (it should accomplish the same results but would avoid the issue of asset purchasing)

   (1c) should assets per se be handled by the certification / recertification process - if the entity does not have the equipment, then it can not be certified; and if it doesn't continue to meet the requirements, it would not be able to meet compliance objectives

   (2) If the PRC-002 requirements were not interconnection-wide, then DT should ask whether or not the obligation for the DME characteristic plans be assigned to the PC or TOP rather than the Regional Entity? PCs and TOPs have a better understanding of their own locality than would a region that may be tempted to homogenize the characteristic requirements

   (3) should ad hoc hardware details (sampling rates, file naming; format) be left to NAESB rather than NERC? Reliability only needs the information - efficiency and commonality would seem to be more related to Business Practices

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Kathleen Goodman	
Organization:	ISO New England	
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

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The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

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   ☒ No

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4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments: none

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Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name: Brian F Thumm		
Organization: ITC Transmission		
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E-mail: bthumm@itctransco.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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   ☐ No

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   ☐ No

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Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	Michael Gammon	
Organization:	Kansas City Power & Light	
Telephone:	816-654-1242	
E-mail:	816-654-1245	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV measures. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: PRC-002: Part of the concern stated in the SAR is the development of criteria for the need for DME, criteria for the placement of DME, criteria for DME monitoring and data capture & retention, and other criteria for data reporting and program review is too open and needs to be tightened. This standard is targeted at a regional level and is an appropriate designation as different regions may have different DME needs. As an example, dense transmission systems with shorter transmission facilities and tight interconnections will have different dynamic characteristics of interest than transmission systems that are much less dense with longer transmission facilities and not as many interconnections. It is appropriate for members of regional operations to work with their regions to establish and document their DME individual regional needs. I am concerned regarding the statement that the standard as written needs to be further defined to eliminate the "fill in the blank" perception. Responding yes, as long this standard does not get so prescriptive that it stifles the abiltiy of the regional entities to develop DME criteria that fits their regional configurations and system characteristics.

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Robert Coish		
Organization: Manitoba Hydro		
Telephone: 204-487-5479		
E-mail: rgcoish@hydro.mb.ca		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☒ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

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The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: It seems that Applicable Reliability Principle number 5, Facilities for communication, monitoring, and control shall be provided, used, and
   maintained for the reliability of interconnected bulk power systems, should also be checked as distubance monitoring is an important system monitoring function in addition to real-time monitoring.

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: Comments need to be provided for a "Yes" response.

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments: There are no comments to submit at this time.

Comment Form — 1st Draft of SAR for Disturbance Monitoring
Project 2007-11

Please use this form to submit comments on the proposed SAR for Disturbance Monitoring. Comments must be submitted by **April 20, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "DME SAR" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT** ☐ **FRCC** ☐ **MRO** ☐ **NPCC** ☐ **RFC** ☐ **SERC** ☐ **SPP** ☐ **WECC** ☐ **NA – Not Applicable**	☐	1 — Transmission Owners
	☐	2 — RTOs and ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
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	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Midwest Standards Collaboration Group

Lead Contact: **Terry Bilke**

Contact Organization: **Midwest ISO**

Contact Segment: **2**

Contact Telephone: **317-249-5463**

Contact E-mail: **tbilke@midwestiso.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
David Lemmons	Xcel Energy	**MRO**	6
Jim Cyrulewski	JDRJC Associates	**RFC**	8

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV measures. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: While the information provided by DME provides value and contributes to reliability, we need to rethink how we apply compliance to technical standards.

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: Assuming that this is handled as a technical standard.

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: It would appear that a Yes answer would need to provide supporting information. There appears to be haste in assembling this comment form.

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments: This particular proposed standard appears to fall into the category of a Technical Standard (refer to the Reliability Standards Development Procedure). The intent of this type of standard is that it measures something or provides information downstream in the reliability process. There is a need for such standards, but they shouldn't be handled the same way as a performance standard (failure of which directly impacts reliability).The FERC Order on the standards suggested NERC could look at creating an "administrative infraction" category for compliance. It seems we have the opportunity to address the fact that there is a need for such standards, but they need to be treated differently than performance or preparedness standards. We don't need to onerous penalties if their DFR encounters a temporary problem or a legacy piece of equipment doesn't provide all the data at the rate required in the new standard.

Comment Form — 1st Draft of SAR for Disturbance Monitoring Project 2007-11

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:	NSRS
Lead Contact:	**James Haigh**
Contact Organization:	**MRO**
Contact Segment:	**10**
Contact Telephone:	**(605)882-7520**
Contact E-mail:	**haigh@wapa.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Neal Balu	WPSR	**MRO**	10
Terry Bilke	MISO	**MRO**	10
Al Boesch	NPPD	**MRO**	10
Larry Brusseau	MRO	**MRO**	10
Robert Coish, Chai	MHEB	**MRO**	10
Carol Gerou	MP	**MRO**	10
Ken Goldsmith	ALT	**MRO**	10
Todd Gosnel	OPPD	**MRO**	10
Jim Haigh	WAPA	**MRO**	10
Pam Oreschnik	XCEL	**MRO**	10
Dick Pursley	GRE	**MRO**	10
Dave Rudolph	BEPC	**MRO**	10
Rick Liljegren	MP	**MRO**	10
Michael Brytowsk, Secretary	MRO	**MRO**	10
27 Additional MRO Members	Not Named Above	**MRO**	10

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

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The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☐ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☐ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments: This proposed standard (SAR) could be considered a technical standard that measures something or provides information to the reliability processes. Failure to meet this standard would not have an immediate effect on reliability. Therefore, the violation risk factors, mitigation time horizon, and violation severity levels should not be as severe as a performance standard. While the standard provides criteria for disturbance monitoring equipment and for collection of data, failure to fully meet these criteria at all times is not a serious reliability concern.

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Name:		
Organization:		
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	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: NPCC CP9, Reliability Standards Working Group

Lead Contact: **Guy V. Zito**

Contact Organization: **Northeast Power Coordinating Council**

Contact Segment: **10**

Contact Telephone: **212-840-1070**

Contact E-mail: **gzito@npcc.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Ralph Rufrano	New York Power Authority	**NPCC**	1
Ron Falsetti	The IESO,Ontario	**NPCC**	2
Roger Champagne	TransEnergie HydroQuebec	**NPCC**	2
Randy Macdonald	New Brunswick System Operator	**NPCC**	2
Herb Schrayshuen	National Grid US	**NPCC**	1
Al Adamson	New York State Reliability Council	**NPCC**	10
Kathleen Goodman	ISO-New England	**NPCC**	2
David Kiguel	Hydro One Networks	**NPCC**	1
William Shemley	ISO-New England	**NPCC**	2
Murale Gopinathan	Northeast Utilities	**NPCC**	1
Guy V. Zito	NPCC	**NPCC**	10
Greg Campoli	New York ISO	**NPCC**	2
Donald Nelson	MA Dept. of Tel. and Energy	**NPCC**	9
Ed Thompson	ConEd	**NPCC**	1
Michael Ranalli	National Grid US	**NPCC**	1
Michael Gildea	Constellation Energy	**NPCC**	5
Michael Schiavone	National Grid US	**NPCC**	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

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The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments: No Further Comment at this time.

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Project 2007-11

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Michael Calimano	
Organization:	New York Independent System Operator	
Telephone:	518-356-6129	
E-mail:	mcalimano@nysio.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
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☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV measures. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: We agree with the project scope as described in the SAR, however please see response to question 4 below.

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments: Interconnected Phasor Measurement Unit (PMU) networks such as North American SynchoPhasor Initiative (NASPI) are not now covered in PRC-002 and PRC-18. We believe this SAR should be revised to indicate that standards relating to such PMU networks are not to be added in these revisions. We believe there should be a separate standard addressing PMU networks. Our reasons for this position are 1) There is enough for 2007-11 to deal with as it is. 2) Composition of the drafting teams for these two efforts should be different. As already indicated in the NERC Glossary definition of Disturbance Monitoring Equipment (DME), equipment that meets the funtional requirements of DME may be identified as a PMU, and any DME may certainly have a PMU output, but PMU network related standards should be addressed in a sepatate standards document.

Comment Form — 1st Draft of SAR for Disturbance Monitoring Project 2007-11

Please use this form to submit comments on the proposed SAR for Disturbance Monitoring. Comments must be submitted by **April 20, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "DME SAR" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Public Service Commission of South Carolina

Lead Contact: **Phil Riley**

Contact Organization: **Public Service Commission of South Carolina**

Contact Segment: **9**

Contact Telephone: **803-896-5154**

Contact E-mail: **philip.riley@psc.sc.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Mignon L. Clyburn	Public Service Commission of SC	**SERC**	9
Elizabeth B. "Lib" Fleming	Public Service Commission of SC	**SERC**	9
G. O'Neal Hamilton	Public Service Commission of SC	**SERC**	9
John E. "Butch" Howard	Public Service Commission of SC	**SERC**	9
Randy Mitchell	Public Service Commission of SC	**SERC**	9
C. Robert "Bob" Moseley	Public Service Commission of SC	**SERC**	9
David A. Wright	Public Service Commission of SC	**SERC**	9

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV measures. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments:

Please use this form to submit comments on the proposed SAR for Disturbance Monitoring. Comments must be submitted by **April 20, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "DME SAR" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Southern Co. Transmission

Lead Contact: **Roman Carter**

Contact Organization: **Southern Co. Transmission**

Contact Segment: **1**

Contact Telephone: **205.257.6027**

Contact E-mail: **jrcarter@southernco.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Marc Butts	Southern Co. Transmission	**SERC**	1
Larry Smith	Alabama Power Co.	**SERC**	3
JT Wood	Southern Co. Transmission	**SERC**	1
Jim Busbin	Southern Co. Transmission	**SERC**	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data Reporting

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV measures. As the electric reliability organization begins enforcing compliance with reliability standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable reliability standards. The Version 0 standards and the translation of Phase III & IV planning measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 translation.

The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments: The question should say if commenter said "yes", provide supporting information.

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments:

Comment Form — 1st Draft of SAR for Disturbance Monitoring Project 2007-11

Please use this form to submit comments on the proposed SAR for Disturbance Monitoring. Comments must be submitted by **April 20, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.net with the abbreviation "DME SAR" in the subject line. If you have questions please contact **David Taylor** at David.Taylor@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
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NERC Region		**Registered Ballot Body Segment**
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)	
Group Name:	WECC Disturbance Monitoring Work Group
Lead Contact:	**Donald Davies**
Contact Organization:	**WECC**
Contact Segment:	**10 - RROs and REs**
Contact Telephone:	**801-582-0353**
Contact E-mail:	**donald@wecc.biz**

Additional Member Name	Additional Member Organization	Region*	Segment*
Peter Mackin	Utility System Efficiencies, Inc.	**WECC**	8
Abraham Ellis	Public Service Company of New Mexico	**WECC**	1
Bharat Bhargava	Southern California Edison Company	**WECC**	1
Bill Miller	Pacific Gas and Electric Company	**WECC**	1
William Mittelstadt	Retired	**WECC**	
Dan Hamai	Western Area Power Administration	**WECC**	1
Darren McCrank	Alberta Electric System Operator	**WECC**	2
Doug Selin	Arizona Public Service Company	**WECC**	1
Fabio Rodriguez	PacifiCorp	**WECC**	1
Fred Henderson	Pacific Gas and Electric Company	**WECC**	1
Harry Lee	British Columbia Hydro and Power Authority	**WECC**	5
James Burns	Bonneville Power Administration	**WECC**	1
John Hauer	Retired	**WECC**	
John Hernandez	Salt River Project	**WECC**	1
John Kehler	Alberta Electric System Operator	**WECC**	2
Ken Martin	Bonneville Power Administration	**WECC**	1
Mike Kwok	British Columbia Transmission Corporation	**WECC**	1
Paqtrick Truong	California Independent System Operator	**WECC**	2

Rikin Shah	NorthWestern Energy	**WECC**	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

This project involves revising the requirements in the following two standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
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The PRC-002 revision and new PRC-018 were recently approved in 2006. In conjunction with this project, the standard drafting team will collect feedback on the strengths and weaknesses of this set of standards from the Operating and Planning Committees and from compliance personnel. The data collected will be used to modify these standards.

PRC-002 is one of the few reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard.

The Federal Energy Regulatory Commission has determined that it will not approve PRC-002 in its current form because the requirements are assigned to the Regional Reliability Organization rather than to a functional entity that is an 'owner, operator, or user' of the bulk power system. The requirements in PRC-002 establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models. This standard addresses some of the recommendations from the studies conducted following the blackout of August 2003.

The standard drafting team will work with stakeholders to review PRC-002 and each of the current regional disturbance monitoring equipment requirements to determine which requirements should be continent-wide requirements and which requirements should be included in regional standards. The requirements in PRC-018 will be revised to properly reference these changes.

The standard drafting team may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)?

   ☒ Yes

   ☐ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11?

   ☐ Yes

   ☒ No

   If "No," please explain why in the comment area below and provide supporting information. Comments:

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.
   Comments:

The Disturbance Monitoring SAR drafting team thanks all those who submitted comments on Draft 1 of the Disturbance Monitoring SAR. This SAR was posted for a 30-day public comment period from March 22 through April 20, 2007. The requester asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 18 sets of comments submitted, including comments from 75 different people from more than 50 organizations representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the SAR drafting team recommends that the Standards Committee accept the revised SAR for Project 2007-11 Disturbance Monitoring for revision of standards:

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data

In response to the comments received, the SAR drafting team has revised the SAR for Project 2007-11 Disturbance Monitoring to add clarification as suggested:

1. The box for item 5 on the Applicable Reliability Principle table of the SAR ("Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems") has been checked.
2. The box for item 7 on the Applicable Reliability Principle table of the SAR ("The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis") has been checked.
3. The last paragraph of the Brief Description of the SAR was modified to begin with "When revising PRC-002 and PRC-018 the SDT will ….".
4. The following sentence was added to the end of the Brief Description of the SAR: "Note: Phasor measurement networks are to be addressed by Project 2008-06."

In addition, the SAR drafting team noted one comment outside the scope of responsibility of the SAR drafting team to resolve. This particular comment has been noted and added as Attachment 2 to the SAR for resolution during standard drafting.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

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 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.

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.	Anita Lee (G2)	AESO		✓								
2.	Darren McCrank (G7)	AESO		✓								
3.	John Kehler (G7)	AESO		✓								
4.	Larry Smith (G1)	Alabama Power Company			✓							
5.	Ken Goldsmith (G5)	ALT	✓				✓					
6.	Doug Selin (G7)	Arizona Public Service Co.	✓		✓							
7.	Harry Lee (G7)	BC Hydro and Power Authority			✓		✓					
8.	Mike Kwok (G7)	BCTC		✓								
9.	Dave Rudolph (G5)	BEPC	✓		✓		✓	✓				
10.	James Burns (G7)	BPA	✓		✓		✓	✓				
11.	Ken Martin (G7)	BPA	✓		✓		✓	✓				
12.	Brent Kingsford (G2)	CAISO		✓								
13.	Paqtrick Truong (G7)	CAISO		✓								
14.	Ed Thompson (G4)	ConEd	✓		✓			✓				
15.	Michael Gildea (G4)	Constellation			✓		✓	✓				
16.	Thomas Owens	Dominion Virginia Power	✓		✓		✓	✓				
17.	Dave Powell	ED Planning and Protection										
18.	Ed Davis	Entergy Services	✓		✓		✓	✓				
19.	Steve Myers (I) (G2)	ERCOT		✓								
20.	Dave Folk	FirstEnergy	✓		✓		✓	✓				
21.	Dick Pursley (G5)	GRE	✓		✓		✓					
22.	David Kiguel (G4)	Hydro One Networks	✓		✓							

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
23.	Roger Champagne (I) (G4)	Hydro-Québec TransÉnergie	✓									
24.	Ron Falsetti (I) (G2) (G4)	IESO		✓								
25.	Matt Goldberg (G2)	ISO-NE		✓								
26.	Kathleen Goodman (I) (G4)	ISO-NE		✓								
27.	William Shemley (G4)	ISO-NE		✓								
28.	Brian Thumm	ITC Transco	✓									
29.	Jim Cyrulewski (G3)	JDRJC Associates								✓		
30.	Mike Gammon	KCP&L	✓		✓		✓	✓				
31.	Donald Nelson (G4)	MA Dept. of Tel. and Energy									✓	
32.	Robert Coish (I) (G5)	Manitoba Hydro	✓		✓		✓	✓				
33.	Terry Bilke (I) (G3) (G5)	MISO		✓								
34.	Carol Gerou (G5)	MP	✓		✓		✓	✓				
35.	Rick Liljegren (G5)	MP	✓		✓		✓	✓				
36.	Larry Brusseau (G5)	MRO										✓
37.	Michael Brytowski (G5)	MRO										✓
38.	Randy Macdonald (G4)	NBSO		✓								
39.	Herb Schrayshuen (G4)	NGRID	✓									
40.	Michael Ranalli(G4)	NGRID	✓									
41.	Michael Schiavone (G4)	NGRID	✓									
42.	Rikin Shah (G7)	Northwestern Energy	✓									
43.	Guy V. Zito (G4)	NPCC										✓
44.	Al Boesch (G5)	NPPC										✓
45.	Murale Gopinathan (G4)	NU	✓									
46.	Mike Calimano (I) (G2)	NYISO		✓								
47.	Greg Campoli (G4)	NYISO		✓								
48.	Al Adamson (G4)	NYSRC	✓									
49.	Todd Gosnell (G5)	OPPD	✓		✓			✓				
50.	Bill Miller (G7)	Pacific Gas & Electric Co.	✓		✓		✓					
51.	Fred Henderson	Pacific Gas & Electric	✓		✓		✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
	(G7)	Co.										
52.	Fabio Rodriguez (G7)	PacifiCorp	✓				✓					
53.	Alicia Daugherty (G2)	PJM		✓								
54.	Abraham Ellis (G7)	PSC of New Mexico									✓	
55.	Phil Riley (G6)	PSC of South Carolina									✓	
56.	Mignon L. Clyburn (G6)	PSC of South Carolina									✓	
57.	Elizabeth B. Fleming (G6)	PSC of South Carolina									✓	
58.	G. O'Neal Hamilton (G6)	PSC of South Carolina									✓	
59.	John e. Howard (G6)	PSC of South Carolina									✓	
60.	Randy Mitchell (G6)	PSC of South Carolina									✓	
61.	C. Robert Moseley (G6)	PSC of South Carolina									✓	
62.	David A. Wright (G6)	PSC of South Carolina									✓	
63.	William Mittelstadt (G7)	Retired	✓									
64.	John Hauer (G7)	Retired										
65.	William Phillips (G2)	RFC, MRO, SERC		✓								
66.	Bharat Bhargava (G7)	SCE	✓				✓					
67.	Roman Carter (G1)	Southern Company Transmission	✓				✓	✓				
68.	Marc Butts (G1)	Southern Company Transmission	✓				✓	✓				
69.	J.T. Wood (G1)	Southern Company Transmission	✓				✓	✓				
70.	Jim Busbin (G1)	Southern Company Transmission	✓				✓	✓				
71.	Charles Yeung (G2)	SPP										✓
72.	John Hernandex (G7)	SRP	✓		✓		✓	✓				
73.	Peter Mackin (G7)	Utility System Efficiencies, Inc.								✓		
74.	James Haigh (G5)	WAPA	✓					✓				
75.	Dan Hamai (G7)	WAPA	✓					✓				
76.	Donald Davies (G7)	WECC										✓
77.	Neal Balu (G5)	WPSR										✓
78.	Pam Oreschnik (G5)	XCEL	✓		✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
79.	David Lemmons (G3)	Xcel Energy	✓		✓		✓	✓				

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – Southern Company Transmission
G2 – IRC Standards Review Committee
G3 – Midwest Standards Collaboration Group
G4 – NPCC CP9 Reliability Standards Working Group
G5 – MRO Members
G6 – Public Service Commission of South Carolina
G7 – WECC Disturbance Monitoring Working Group

Index to Questions, Comments, and Responses

1. Do you believe that there is a reliability-related need to address revisions to PRC-002 and PRC-018 — disturbance equipment installation, monitoring, and reporting so that both standards are enforceable and complement one another? If "No," please explain.

Summary Consideration: Almost all commenters indicated they do think there is a reliability-related need to revise PRC-002 and PRC-018. One commenter suggested that Reliability Principle #5 applies to these two standards and the drafting team revised the SAR to include that principle:

> 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Entergy Services		☑	We do not think there is a reliability-related need to revise PRC-002 and PRC-018. However, we do agree that it will be a worthwhile effort to revise the two standards to make them: enforceable by FERC, more compatable with each other, and to address FERC staff and FERC comments.
Response: Thank you for the comment. The SAR drafting team will proceed with our recommendation for the revision of PRC-002 and PRC-018.			
Midwest SCG	☑	☑	While the information provided by DME provides value and contributes to reliability, we need to rethink how we apply compliance to technical standards.
Response: Compliance is an issue the SAR drafting team cannot respond to; however, the standard drafting team for Project 2007-11 will be required to propose the compliance elements of these standards and Midwest SCG can comment on the compliance elements when the standards are posted for public comment.			
KCP&L	☑		PRC-002: Part of the concern stated in the SAR is the development of criteria for the need for DME, criteria for the placement of DME, criteria for DME monitoring and data capture & retention, and other criteria for data reporting and program review is too open and needs to be tightened. This standard is targeted at a regional level and is an appropriate designation as different regions may have different DME needs. As an example, dense transmission systems with shorter transmission facilities and tight interconnections will have different dynamic characteristics of interest than transmission

Question #1			
Commenter	**Yes**	**No**	**Comment**
			systems that are much less dense with longer transmission facilities and not as many interconnections. It is appropriate for members of regional operations to work with their regions to establish and document their DME individual regional needs. I am concerned regarding the statement that the standard as written needs to be further defined to eliminate the "fill in the blank" perception. Responding yes, as long this standard does not get so prescriptive that it stifles the ability of the regional entities to develop DME criteria that fits their regional configurations and system characteristics.
Response: PRC-002 is a fill-in-the-blank standard which is being revised as directed by FERC. It is anticipated that as part of this Project 2007-11 an over-arching continent-wide PRC-002 standard will be developed and coordinated with the development of eight regional standards. You will have the opportunity to comment on the continent-wide and related regional standards as they are posted for public comment. You can then comment on the individual standards and to the extent that you feel either is so prescriptive that it stifles the ability of the regional entities to develop DME criteria that fit their regional configurations and system characteristics you may comment accordingly.			
Manitoba Hydro	☑		It seems that Applicable Reliability Principle number 5, Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems, should also be checked as disturbance monitoring is an important system monitoring function in addition to real-time monitoring.
Response: The SAR drafting team agrees with your comment and has checked the box for item 5 on the Applicable Reliability Principle table of the SAR.			
Southern Company Transmission	☑		
FirstEnergy	☑		
Hydro-Québec TransÉnergie	☑		
Dominion VA Power	☑		
ERCOT	☑		
IESO	☑		
IRC SRC	☑		

Question #1			
Commenter	**Yes**	**No**	**Comment**
ISO-NE	☑		
ITC Transco	☑		
NPCC CP9 RSWG	☑		
NYISO	☑		
PSC of South Carolina	☑		
WECC DMWG	☑		

2. Do you agree with the scope of the proposed project (the scope includes all the items noted in the SAR as well as other improvements to the standards that meet the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards)? If "No," please explain.

Summary Consideration: Almost all commenters indicated agreement with the scope of the proposed SAR. One commenter indicated that the SAR should be revised to require the SDT to revise and address current regional programs developed in accordance with PRC-018, and the drafting team modified the SAR in support of the intent of this comment.

Question #2			
Commenter	**Yes**	**No**	**Comment**
FirstEnergy		☑	RFC is in the process of developing a Disturbance Monitoring Equipment standard based on NERC standards PRC-002 and PRC-018. The SAR requires the SDT to review PRC-002 and each of the current regional programs developed in accordance to that standard. The SAR should be revised to require the SDT to review and address the current regional programs developed in accordance to PRC-018.
Response: The SAR drafting Team modified the last paragraph of the Brief Description of the SAR to begin with "When revising PRC-002 and PRC-018 the SDT will ….".			
Midwest SCG	☑		Assuming that this is handled as a technical standard.
Response: The standards process requires that all standards be addressed through the same puplic posting and commenting process.			
NYISO	☑		We agree with the project scope as described in the SAR, however please see response to question 4 below.
Response: Please see the response to the comments on question 4.			
Southern Company Transmission	☑		
Entergy Services	☑		
Hydro-Québec TransÉnergie	☑		
Dominion VA Power	☑		
ERCOT	☑		

Question #2			
Commenter	**Yes**	**No**	**Comment**
IESO	☑		
IRC SRC	☑		
ISO-NE	☑		
ITC Transco	☑		
KCP&L	☑		
Manitoba Hydro	☑		
NPCC CP9 RSWG	☑		
PSC of South Carolina	☑		
WECC DMWG	☑		

3. Are there additional revisions beyond those identified in the SAR that should be addressed within the scope of this Project 2007-11? If "No," please explain.

Summary Consideration: There was an error on the comment form, and the statement that asked, 'If 'No' please explain – should have asked, 'If 'Yes' please explain. Stakeholders did not provide a list of additional revisions for inclusion in the scope of this project.

Question #3			
Commenter	**Yes**	**No**	**Comment**
Dominion VA Power		☑	There are specific changes needed, but the general SAR process steps listed should identify needed changes. Details can be worked out during drafting of changes.
Response: Thank you for your comment. The SAR drafting team encourages your review and comment on the standard itself when it is posted for comment.			
Southern Company Transmission		☑	The question should say if commenter said "yes", provide supporting information.
Response: The SAR drafting team agrees with your comment.			
FirstEnergy		☑	It appears this question is worded incorrectly such that it requires an explanation for a "Yes" response rather than an explanation for a "No" response.
Response: The SAR drafting team agrees with your comment.			
Manitoba Hydro		☑	Comments need to be provided for a "Yes" response.
Response: The SAR drafting team agrees with your comment.			
Midwest SCG		☑	It would appear that a Yes answer would need to provide supporting information. There appears to be haste in assembling this comment form.
Response:			

Question #3			
Commenter	**Yes**	**No**	**Comment**
The SAR drafting team agrees that a "Yes" answer would need to provide supporting information.			
Entergy Services		☑	
Hydro-Québec TransÉnergie		☑	
ERCOT		☑	
IESO		☑	
IRC SRC		☑	
ISO-NE		☑	
ITC Transco		☑	
KCP&L		☑	
NPCC CP9 RSWG		☑	
NYISO		☑	
PSC of South Carolina		☑	
WECC DMWG		☑	

4. Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.

Summary Consideration: Almost all commenters indicated they do think there is a reliability-related need to revise PRC-002 and PRC-018.

- One commenter suggested that Reliability Principle #5 and Reliability Principle #7 apply to these two standards and the drafting team revised the SAR to include these principles:
  5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
  7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
- One commenter suggested clarifying that Phasor Measurement Networks are outside the scope of this SAR and the drafting team modified the SAR to include a phrase indicating that Phasor Measurement Networks will be addressed in Project 2008-06.
- One set of commenters suggested industry discussion on some of the technical details within the scope of the standards addressed by this SAR and the drafting team added this list of issues to the SAR as topics to be addressed by the standard drafting team.

Question #4	
Commenter	**Comment**
FirstEnergy	Please revise the Brief Description to include any special conside The SAR drafting team added the following clarifying sentence to the Brief Description of the SAR: “Phasor measurement networks are to be addressed by Project 2008-06.” rations for PRC-018 similar to the special considerations for PRC-002. Perhaps the last paragraph is applicable to both PRC-002 and PRC-018 standards but it is not clear. For the Applicable Reliability Principles Table on page 4, boxes 5 and 7 should also be checked since they refer to system monitoring.
Response: The SAR drafting Team modified the last paragraph of the Brief Description of the SAR to begin with “When revising PRC-002 and PRC-018 the SDT will ….”. In addition, Boxes 5 and 7 have been checked on the Applicable Reliability Principle table of the SAR.	
MRO Members	This proposed standard (SAR) could be considered a technical standard that measures something or

<table>
<tr><th colspan="2">Question #4</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td></td><td>provides information to the reliability processes. Failure to meet this standard would not have an immediate effect on reliability. Therefore, the violation risk factors, mitigation time horizon, and violation severity levels should not be as severe as a performance standard. While the standard provides criteria for disturbance monitoring equipment and for collection of data, failure to fully meet these criteria at all times is not a serious reliability concern.</td></tr>
<tr><td colspan="2">Response:

Compliance is an issue the SAR drafting team cannot respond to; however, the standard drafting team for Project 2007-11 will be required to propose the compliance elements of these standards and MRO Members can comment on the compliance elements when the standards are posted for public comment.</td></tr>
<tr><td>NYISO</td><td>Interconnected Phasor Measurement Unit (PMU) networks such as North American SynchoPhasor Initiative (NASPI) are not now covered in PRC-002 and PRC-18. We believe this SAR should be revised to indicate that standards relating to such PMU networks are not to be added in these revisions. We believe there should be a separate standard addressing PMU networks. Our reasons for this position are 1) There is enough for 2007-11 to deal with as it is. 2) Composition of the drafting teams for these two efforts should be different. As already indicated in the NERC Glossary definition of Disturbance Monitoring Equipment (DME), equipment that meets the functional requirements of DME may be identified as a PMU, and any DME may certainly have a PMU output, but PMU network related standards should be addressed in a separate standards document.</td></tr>
<tr><td colspan="2">Response:

The SAR drafting team added the following clarifying sentence to the Brief Description of the SAR:

“Phasor measurement networks are to be addressed by Project 2008-06.”</td></tr>
<tr><td>IRC SRC</td><td>The SDT should pose questions regarding:
(1a) whether or not NERC should require data recording performance requirements that can only be met by purchasing specific assets

(1b) if it is sufficient to mandate what information and performance is required rather than the hardware itself (it should accomplish the same results but would avoid the issue of asset purchasing)

(1c) should assets per se be handled by the certification / recertification process - if the entity does not have the equipment, then it can not be certified; and if it doesn't continue to meet the requirements, it would not be able to meet compliance objectives</td></tr>
</table>

Question #4	
Commenter	**Comment**
	(2) If the PRC-002 requirements were not interconnection-wide, then DT should ask whether or not the obligation for the DME characteristic plans be assigned to the PC or TOP rather than the Regional Entity? PCs and TOPs have a better understanding of their own locality than would a region that may be tempted to homogenize the characteristic requirements (3) should ad hoc hardware details (sampling rates, file naming; format) be left to NAESB rather than NERC? Reliability only needs the information - efficiency and commonality would seem to be more related to Business Practices.
Response: The IRC SRC raises questions which are outside the responsibility of the SAR drafting team. It is anticipated that as part of this Project 2007-11 PRC-002 and PRC-018 will be revised and coordinated with the development of eight related regional standards. You will have the opportunity to comment on the continent-wide and related regional standards as they are posted for public comment. The SAR drafting team also encourages members of the IRC SRC to actively participate in the standards development processes at the continent-wide and regional levels. The SAR drafting team will note IRC SRC's comments in the SAR for consideration by the standard drafting team during the development of the standard.	
Midwest SCG	This particular proposed standard appears to fall into the category of a Technical Standard (refer to the Reliability Standards Development Procedure). The intent of this type of standard is that it measures something or provides information downstream in the reliability process. There is a need for such standards, but they shouldn't be handled the same way as a performance standard (failure of which directly impacts reliability).The FERC Order on the standards suggested NERC could look at creating an "administrative infraction" category for compliance. It seems we have the opportunity to address the fact that there is a need for such standards, but they need to be treated differently than performance or preparedness standards. We don't need to onerous penalties if their DFR encounters a temporary problem or a legacy piece of equipment doesn't provide all the data at the rate required in the new standard.
Response: Compliance is an issue the SAR drafting team cannot respond to; however, the standard drafting team for Project 2007-11 will be required to propose the compliance elements of these standards and Midwest SCG can comment on the compliance elements when the standards are posted for public comment.	
Dominion VA Power	No comments until first draft is posted.
ERCOT	No further comments at this time.

Question #4	
Commenter	**Comment**
Manitoba Hydro	There are no comments to submit at this time.
NPCC CP9 RSWG	No further comment at this time.

Standard Authorization Request Form

Title of Proposed Standard:	Disturbance Monitoring (Project 2007-11)
Request Date: Revised Date:	March 1, 2007 May 21, 2007

SAR Requester Information

Name:	Robert W. Millard on behalf of the Regional Reliability Standards Working Group	***SAR Type (Check one box.)***	
Company:	Reliability*First* Corporation	☐	New Standard
Telephone:	(708) 588-9886	☒	Revision to Existing Standard
Fax:	(330) 456-3648	☐	Withdrawal of Existing Standard
E-mail:	bob.millard@rfirst.org	☐	Urgent Action

Purpose *(Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.)*

To establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models.

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV Planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV Planning Measures. As the Electric Reliability Organization begins enforcing compliance with Reliability Standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable Reliability Standards. The Version 0 standards and the translation of Phase III & IV Planning Measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards, Phase III & IV standards, and recent updates were put in place as a temporary starting point to start-up the Electric Reliability Organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and Phase III & IV translations.

Industry Need *(Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)*

1. Provide an adequate level of reliability for the North American bulk power systems — ensure the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties — ensure

   (a) the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined,

   (b) the purpose, requirements, and measures are results-focused and unambiguous and

   (c) the consequences of violating the requirements are clear.
3. Consider comments received during the initial development of this set of standards and other comments received from ERO regulatory authorities and stakeholders as described in the Detailed Description section below.
4. Bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure as described in Attachment 1 below.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Brief Description *(Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)*

PRC-002 and PRC-018 were approved in 2006.

PRC-002 is one of four reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard. The standard drafting team (SDT) will review PRC-002 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to or contained with the disturbance monitoring program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

When revising PRC-002 and PRC-018 the SDT will, the SDT shall consider comments and issues as described in the Detailed Description section and Attachment 1 below for drafting and including other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders through the standards development procedure, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Note: Phasor measurement networks are to be addressed by Project 2008-06.

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check all boxes that apply.)	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☒	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
Recognizing that reliability is an essential requirement of a robust North American economy:
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description *(Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)*

1. The SDT shall consider the following comments (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006),
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application, and
    - Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development).
    - Phase III & IV Standard Drafting Team
    - Violation Risk Factors Drafting Team

    PRC-002 Define and Document Disturbance Monitoring Equipment Requirements

    FERC NOPR

    - Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information related to the fill-in-the-blank aspects of this standard as further defined below under "Regional Fill-in-the-Blank Team Comments".

    FERC Staff Report

    - This standard designates RROs as the applicable entity. Staff is concerned about the appropriateness of RROs serving as the applicable entity in the new mandatory standards structure. These standards have been referred to as "fill-in-the-blank" standards (see comments under "Regional Fill-in-the-Blank Team Comments" below).

    Phase III/IV comments

    - There are no criteria that the RROs must use in specifying the process for identifying locations where DMEs are required (to be addressed when considering issues under "Regional Fill-in-the-Blank Team Comments" below).

    Violation Risk Factor Drafting Team Comments

    - R1 - This standard and all related sub requirements are after the fact data analysis.

    Regional Fill-in-the-Blank Team Comments

    - Determine what elements (if any) should be included in the North American standard and what elements should be included in the regional standards.
    - Development of regional standards needs to be coordinated with regional entities.
    - Regional entities should be notified to begin process for developing regional standards once the standard drafting team has determined what elements should be included in the continent-wide standard and what elements should be included in the regional standards.

    PRC-018 Disturbance Monitoring Equipment Installation and Data

    Violation Risk Factor Drafting Team Comments

    - R3.4, 3.5, 3.6, 3.7 – Requirements as written are ambiguous and need more clearly defined.

2. The SDT will bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure as described in Attachment 1 below.

3. The SDT should also consider any other issues that were not completely captured but were stated or referenced in the above materials.

4. The SDT should consider issues raised by the industry during the posting of the SAR for Project 2007-11 during the first comment period from March 22 through April 20, 2007, attached as Attachment 2.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Attachment 1

Excerpts from the *Reliability Standards Development Procedure Manual, Version 6* and the *ERO Rules of Procedure*:

(The drafting team will reference and follow, as appropriate, the following guidelines *(or later version as appropriate)* in determining what changes to make to the standards to bring them into conformance with these guidelines.)

Standard Review Guidelines

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language

Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality

Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements

In general, requirements for entities to have ‘capabilities’ (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to ‘maintain’ their capabilities.

Consistent Terminology

To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a ‘unique’ definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.

- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply.

If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Functional Model Version 3

Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Attachment 2

Issues Raised by Industry During 1st Posting of SAR for Project 2007-11 Which are Outside the Responsibility of the SAR Drafting Team

Question 4 of the Comment Form: *Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.*

IRC Standards Review Committee commented:

The SDT should pose questions regarding:

(1a) whether or not NERC should require data recording performance requirements that can only be met by purchasing specific assets

(1b) If it is sufficient to mandate what information and performance is required rather than the hardware itself (it should accomplish the same results but would avoid the issue of asset purchasing)

(1c) Should assets per se be handled by the certification / recertification process - if the entity does not have the equipment, then it can not be certified; and if it doesn't continue to meet the requirements, it would not be able to meet compliance objectives

(2) If the PRC-002 requirements were not interconnection-wide, then DT should ask whether or not the obligation for the DME characteristic plans be assigned to the PC or TOP rather than the Regional Entity? PCs and TOPs have a better understanding of their own locality than would a region that may be tempted to homogenize the characteristic requirements

(3) Should ad hoc hardware details (sampling rates, file naming; format) be left to NAESB rather than NERC? Reliability only needs the information - efficiency and commonality would seem to be more related to Business Practices.

Standard Authorization Request Form

Title of Proposed Standard:	Disturbance Monitoring (Project 2007-11)
Request Date: Revised Date:	March 1, 2007 May 21, 2007

SAR Requester Information

Name:	Robert W. Millard on behalf of the Regional Reliability Standards Working Group	***SAR Type (Check one box.)***	
Company:	Reliability*First* Corporation	☐	New Standard
Telephone:	(708) 588-9886	☒	Revision to Existing Standard
Fax:	(330) 456-3648	☐	Withdrawal of Existing Standard
E-mail:	bob.millard@rfirst.org	☐	Urgent Action

Purpose *(Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.)*

To establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models.

PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
PRC-018 — Disturbance Monitoring Equipment Installation and Data

PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV Planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV Planning Measures. As the Electric Reliability Organization begins enforcing compliance with Reliability Standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable Reliability Standards. The Version 0 standards and the translation of Phase III & IV Planning Measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards, Phase III & IV standards, and recent updates were put in place as a temporary starting point to start-up the Electric Reliability Organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and Phase III & IV translations.

Industry Need *(Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation*.)

1. Provide an adequate level of reliability for the North American bulk power systems — ensure the standards are complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties — ensure

   (a) the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined,

   (b) the purpose, requirements, and measures are results-focused and unambiguous and

   (c) the consequences of violating the requirements are clear.
3. Consider comments received during the initial development of this set of standards and other comments received from ERO regulatory authorities and stakeholders as described in the Detailed Description section below.
4. Bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure as described in Attachment 1 below.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Brief Description *(Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)*

PRC-002 and PRC-018 were approved in 2006.

PRC-002 is one of four reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard. The standard drafting team (SDT) will review PRC-002 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to or contained with the disturbance monitoring program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.

When revising PRC-002 and PRC-018 the SDT will, ~~T~~ the SDT shall consider comments and issues as described in the Detailed Description section and Attachment 1 below for drafting and including other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders through the standards development procedure, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Note: Phasor measurement networks are to be addressed by Project 2008-06.

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check all boxes that apply.)	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☒	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
Recognizing that reliability is an essential requirement of a robust North American economy:
1. A reliability standard shall not give any market participant an unfair competitive advantage.Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

***Detailed Description** (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)*

1. The SDT shall consider the following comments (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006),
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application, and
    - Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development).
    - Phase III & IV Standard Drafting Team
    - Violation Risk Factors Drafting Team

PRC-002 Define and Document Disturbance Monitoring Equipment Requirements

FERC NOPR

- Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information related to the fill-in-the-blank aspects of this standard as further defined below under "Regional Fill-in-the-Blank Team Comments".

FERC Staff Report

- This standard designates RROs as the applicable entity. Staff is concerned about the appropriateness of RROs serving as the applicable entity in the new mandatory standards structure. These standards have been referred to as "fill-in-the-blank" standards (see comments under "Regional Fill-in-the-Blank Team Comments" below).

Phase III/IV comments

- There are no criteria that the RROs must use in specifying the process for identifying locations where DMEs are required (to be addressed when considering issues under "Regional Fill-in-the-Blank Team Comments" below).

Violation Risk Factor Drafting Team Comments

- R1 - This standard and all related sub requirements are after the fact data analysis.

Regional Fill-in-the-Blank Team Comments

- Determine what elements (if any) should be included in the North American standard and what elements should be included in the regional standards.
- Development of regional standards needs to be coordinated with regional entities.
- Regional entities should be notified to begin process for developing regional standards once the standard drafting team has determined what elements should be included in the continent-wide standard and what elements should be included in the regional standards.

PRC-018 Disturbance Monitoring Equipment Installation and Data

Violation Risk Factor Drafting Team Comments

- R3.4, 3.5, 3.6, 3.7 – Requirements as written are ambiguous and need more clearly defined.

2. The SDT will bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure as described in Attachment 1 below.

3. The SDT should also consider any other issues that were not completely captured but were stated or referenced in the above materials.

4. The SDT should consider issues raised by the industry during the posting of the SAR for Project 2007-~~0~~11 during the first comment period from March 22 through April 20, 2007, attached as Attachment 2.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Attachment 1

Excerpts from the *Reliability Standards Development Procedure Manual, Version 6* and the *ERO Rules of Procedure*:

(The drafting team will reference and follow, as appropriate, the following guidelines *(or later version as appropriate)* in determining what changes to make to the standards to bring them into conformance with these guidelines.)

Standard Review Guidelines

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language

Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality

Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements

In general, requirements for entities to have ‘capabilities’ (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to ‘maintain’ their capabilities.

Consistent Terminology

To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a ‘unique’ definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

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- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
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Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. (‘Violation severity levels’ replace existing ‘levels of non-compliance.’) The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

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Compliance Monitor

Replace, ‘Regional Reliability Organization’ with ‘Regional Entity’

Fill-in-the-blank Requirements

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If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Functional Model Version 3

Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Attachment 2

Issues Raised by Industry During 1st Posting of SAR for Project 2007-11 Which are Outside the Responsibility of the SAR Drafting Team

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(1a) whether or not NERC should require data recording performance requirements that can only be met by purchasing specific assets

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

June 12, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Nomination Period Opens for Standard Drafting Team

The Standards Committee announces the following standards action:

Nominations for Project 2007-11 — Disturbance Monitoring Standard Drafting Team (June 12–25, 2007)

The Standards Committee is seeking industry experts to serve on the Disturbance Monitoring Standard Drafting Team (Project 2007-11). If you are interested in serving on this team, please complete this nomination form and return it to sarcomm@nerc.net with "DME SDT Nomination" in the subject line by **June 25, 2007**. For questions, please contact David Taylor at 609-651-5089 or dave.taylor@nerc.net.

The drafting team will hold its first meeting August 7–9, 2007. This project involves upgrading the overall quality of the two standards below; eliminating some gaps in the requirements; and eliminating some "fill-in-the-blank" components:

- PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements
- PRC-018 — Disturbance Monitoring Equipment Installation and Data

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Standard Development Roadmap

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

Development Steps Completed:

1. Nominations for the SAR drafting team members were solicited February 26–March 9, 2007.
2. The SAR was posted for a 30 day comment period March 22–April 20, 2007.
3. Nominations for the standard drafting team (SDT) for Project 2007-11 Disturbance Monitoring were solicited June 12–25, 2007.

Proposed Action Plan and Description of Current Draft:

The purpose of this standard is to establish requirements for recording and reporting sequence of events (SOE) data, fault recording (FR) data, and dynamic disturbance recording (DDR) data to facilitate analysis of Disturbances. This standard will replace PRC-002-1 and PRC-018-1.

The purpose of revising the above standards is to:

1. Ensure each of the standards is complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure they are enforceable as mandatory reliability standards with financial penalties; the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in NERC's Reliability Standards Development Plan: 2007-2009 (summarized and outlined in the Reliability Standard Review Guidelines attached as Appendix A).
4. Consider the items mentioned in the Standard Review Forms (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) attached as Appendix B, prepared by the NERC staff, which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
    - Version 0 standards development, and
    - Regional Reliability Standards Working Group (RRSWG – a NERC working group involved with regional standards development).

The standard drafting team (SDT) also considered the following additional issues that were not completely captured but were stated or referenced in the above materials.

1. Modify PRC-002-1 to remove RRO in the applicability and eliminate the reference to RRO in PRC-018-1.
2. Create continent wide requirements applicable to Transmission Owners and Generation Owners.
3. The new standard (PRC-002-2) is being proposed based on the requirements of the existing PRC-002-1 and PRC-018-1 standards and a recommendation for replacing both of these existing standards is being proposed. The requirements in PRC-018-1 are being incorporated into PRC-002-2 with the exception of the maintenance and testing requirements in PRC-018-1.
4. Satisfy the standards procedure requirement for five-year review of the standards.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop and post reply comments to initial posting of standard	March 30–April 20, 2009
2. Post for second 30-day comment period	June, 2009
3. Post for 30-day pre-ballot period.	September, 2009
4. Conduct initial ballot	December, 2009
5. Post response to comments on first ballot	January, 2010
6. Conduct recirculation ballot	February, 2010
7. Board adoption date.	To be determined.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Substation[1] — 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.

[1] This definition is from IEEE C2-2002

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-2

3. **Purpose:** To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES).

4. **Applicability:**

    4.1. Transmission Owners with Substations having Facilities rated at 200 kV or above

    4.2. Generator Owners with any one of the following connected to the transmission system at 200 kV or above:

    - Generating units having a single generating unit of 500 MVA or higher nameplate rating
    - Generating plants with an aggregate plant total nameplate capacity of 1500 MVA or higher

5. **Effective Date:**

    Requirements R1 through R11:

    - 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:
        - Each Responsible Entity shall be at least 50% compliant on monitored equipment
    - 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 four years after Board of Trustees adoption:
        - Each Responsible Entity shall be 100% compliant on monitored equipment.

    Requirements R12 and R13

    - First day of first calendar quarter eighteen months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Transmission Owner shall record (or have a process in place to derive) the Sequence of Events data for changes in circuit breaker position (open/close) for each of its circuit breakers operated at 200 kV and above at each Substation that meets the following criteria:

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.

R1.2. Connected at 200 kV or above through generating unit step up transformer(s) (GSU(s)) to a generating plant having either a single generating unit of 500 MVA or higher nameplate rating, or through a GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher.

R2. Each Generator Owner shall record (or have a process in place to derive) the Sequence of Events data for changes in circuit breaker position (open/close) for its equipment identified in Table 2-1:

Table 2-1: Generator Owner's Requirement R2 for Sequence of Events Data

Location	Equipment
Each generating plant having either a single generating unit with a nameplate rating of 500 MVA or higher, and connected to the transmission system at 200 kV and above	Each generator output circuit breaker, including low side breakers
Each generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher, and connected to the transmission system at 200 kV and above	Each generator output circuit breaker, including low side breakers
Each Substation connected at 200 kV or above through GSU(s) to a generating plant having a single generating unit with a nameplate rating of 500 MVA or higher	Each circuit breaker 200 kV and above
Each Substation at 200 kV or above connected through GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher	Each circuit breaker 200 kV and above

R3. Each Transmission Owner and Generator Owner 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) for each of its circuit breakers specified in Requirements R1 and R2.

R4. Each Transmission Owner shall record (or have a process in place to derive) the following Fault Recording data for its equipment identified in Table 4-1:

R4.1. The three phase to neutral voltages on each monitored line or bus as follows:

- On ring buses, the voltages of bus sections connected to transmission lines.
- On breaker-and-a-half arrangements, the outer bus voltages, or the individual line voltages.
- On straight buses, common bus voltages or the individual line voltages.

R4.2. The three phase currents and the residual or neutral currents of each monitored line and transformer.

Table 4-1: Transmission Owner's Requirement R4 for Fault Recording Data

Location	Equipment
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 Each Substation connected at 200 kV or above through generating unit step up transformer(s) to a generating plant having a single generating unit of 500 MVA or higher nameplate rating Each Substation connected at 200 kV or above through generating unit step up transformer(s) to an aggregate plant with a total nameplate capacity of 1500 MVA or higher	• Each transmission line operated at 200 kV or above that does not have fault data recorded at its remote terminal • Each transmission bus operated at 200 kV or above • Each transformer having low-side operating voltage of 200 kV or above

R5. Each Generator Owner shall record (or have a process in place to derive) the following Fault Recording data for its equipment identified in Table 5-1:

R5.1. The three phase to neutral voltages or phase to phase voltages on Generator Step-up Transformers (GSU(s)) from the high voltage side or low voltage side of the GSU, or from the generator bus.

R5.2. The three phase currents of GSU(s) from the high voltage side or low voltage side of the GSU, or from the generator bus.

R5.3. The neutral current of wye connected GSU(s) high voltage windings.

R5.4. The three phase to neutral voltages on each monitored line or bus as follows:

- On ring buses, the voltages of bus sections connected to transmission lines.
- On breaker-and-a-half arrangements, the outer bus voltages, or the individual line voltages.
- On straight buses, common bus voltages or the individual line voltages.

R5.5. The three phase currents and the residual or neutral currents of each monitored line and transformer.

Table 5-1: Generator Owner's Requirement R5 for Fault Recording Data

Location	Equipment
Each generating plant having either a single generating unit with a nameplate rating of 500 MVA or higher, and connected to the transmission system at 200 kV and above Each generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher, and connected to the transmission system at 200 kV and above	Each GSU with a high side of 200 kV and above
Each Substation connected at 200 kV or above through GSU(s) to a generating plant having a single generating unit with a nameplate rating of 500 MVA or higher Each Substation at 200 kV or above connected through GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher	• Each transmission line operated at 200 kV or above that does not have fault data recorded d at its remote terminal • Each bus operated at 200 kV or above • Each transformer having low-side operating voltage of 200 kV or above

R6. Each Transmission Owner and Generator Owner shall have Fault Recording data for its equipment identified in Requirements R4 and R5 that conforms to the following:

R6.1. A single record or multiple records that include the following:

- A pre trigger record length of at least two cycles and a post trigger record length of at least 50 cycles

  OR

- At least two cycles of the pre trigger event; the first three cycles of an event; and the final cycle of an event.

R6.2. A minimum recording rate of 16 samples per cycle.

R7. 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, then for each Substation having a total of seven or more transmission lines connected at 200 kV or above, the Transmission Owner shall record (or have a process in place to derive) the following DDR data:

R7.1. At least one phase-to-neutral voltage at each voltage level of 200 kV and above.

R7.2. Frequency (at least one at the required Substation).

R7.3. At least one phase current (on the same phase and at the same voltage as the voltage monitored in R7.1) (for each line operated at 200 kV and above).

R7.4. Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis (for each line operated at 200 kV and above)

R8. Each Generator Owner shall record (or have a process in place to derive) the following DDR data at each of its generating plants with an aggregate nameplate rating of 1500 MVA or higher for each GSU that has a transformer high side connected at 200 kV or above:

R8.1. At least one phase-to-neutral voltage or one phase-to-phase voltage at either the GSU's high side or low side voltage level, or the generator bus voltage.

R8.2. Frequency (at least one at the required Substation)

R8.3. At least one phase current (on the same phase and at the same voltage as the voltage monitored in Requirement R8.1) or two phase currents for phase-to-phase voltages for each GSU.

R8.4. Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis (per each monitored element) for each GSU.

R9. Each Transmission Owner and Generator Owner that has DDR devices (to meet Requirement R7 or R8) shall manage its DDR data in accordance with the following technical specifications:

R9.1. Use the same phase for voltage and current recordings.

R9.2. Collect at least 960 samples per second to calculate RMS electrical quantities.

R9.3. Store calculated RMS values of electrical quantities at a rate of at least 6 times per second.

R10. Each Transmission Owner and Generator Owner that installs a DDR device after January 1, 2011 to meet Requirements R7, R8 and R9 shall install a device that is capable of continuous recording.

R11. Each Transmission Owner and Generator Owner that has a DDR device (to meet Requirements R7, R8 and R9) that does not have continuous recording capability shall set its device to trigger and record according to the following:

R11.1. For rate-of-change of frequency.

R11.2. For oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range.

R11.3. Set data record lengths at a minimum of three minutes.

R12. Each Transmission Owner and Generator Owner shall synchronize all of its Sequence of Event, Fault Recording, and DDR functions to within +/- 2 milliseconds of Universal Coordinated Time (UTC) with the associated hour offset.

R13. Each Transmission Owner and Generator Owner shall have all recorded Sequence of Event, Fault Recording, and DDR data available (locally or remotely) for 10 calendar days after a Disturbance.

C. Measures

M1. (To be added later)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

(To be added later.)

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

1.3.1 Each Transmission Owner and Generator Owner shall retain all data provided to the Regional Entity, Reliability Coordinator or NERC for at least three years following the event.

1.3.2 Each Transmission Owner and Generator Owner shall each maintain, and report to the Regional Entity, Reliability Coordinator or NERC within 30 calendar days of a request, the following information for Sequence of Event, Fault Recording, and Dynamic Disturbance Recording data:

- Location
- Make and model of equipment
- Type of data source (Sequence of Events, Fault Recording, or Dynamic Disturbance Recording).
- Monitored elements, such as transmission circuit, bus section, circuit breakers, etc.

1.4. Compliance Monitoring and Assessment Processes

(To be added later)

1.5. Additional Compliance Information

1.5.1 Each Transmission Owner and Generator Owner shall meet all of the following criteria when reporting Sequence of Event, Fault Recording , and Dynamic Disturbance Recording data to its Regional Entity, Reliability Coordinator, or NERC:

- All Sequence of Event, Fault Recording, and Dynamic Disturbance Recording data shall be provided to the Regional Entity, Reliability Coordinator, or NERC within 30 calendar days of a request,
- All Fault Recording and Dynamic Disturbance Recording data shall be in a format such that any software system capable of viewing and analyzing COMTRADE (IEEE Std. C37.111-1999 or successor) files may be used to process and evaluate the data,
- All known delays in interposing relays shall be reported along with the SOE data,
- All data files shall be named in conformance with IEEE C37.232-2007, or its successor, Recommended Practice for Naming Time Sequence Data Files.

2. Violation Severity Levels (To be added later)

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL

E. Regional Variances

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form for First Draft of PRC-002-2 — Disturbance Monitoring and Reporting Requirements (Project 2007-11)

Please **DO NOT** use this form to submit comments. Please use the electronic comment form located at the link below to submit comments on the proposed first draft of reliability standard PRC-002-2. Comments must be submitted by **8:00 p.m. EDT on March 18, 2009**. If you have questions please contact Stephanie Monzon at stephanie.monzon@nerc.net or by telephone at 610-608-8084.

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

Background Information

The purpose of this standard is to establish requirements for recording and reporting sequence of events (SOE) data, fault recording (FR) data, and dynamic disturbance recording (DDR) data to facilitate analysis of Disturbances. This standard will replace PRC-002-1 and PRC-018-1.

The purpose of revising the above standards is to:

1. Ensure each of the standards is complete and the requirements are set at an appropriate level to ensure reliability.

2. Ensure the revised standard is enforceable as a mandatory reliability standard with financial penalties; the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.

3. Incorporate other general improvements described in NERC's Reliability Standards Development Plan: 2007-2009 (summarized and outlined in the Reliability Standard Review Guidelines attached as Appendix A).

4. Consider the items mentioned in the Standard Review Forms (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) attached as Appendix B, prepared by the NERC staff, which attempt to capture comments from the:
    - FERC NOPR (Docket # RM06-16-00 dated October 20, 2006) ,
    - FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application,
    - Version 0 standards development (see note 1), and
    - Regional Reliability Standards Working Group (RRSWG — a NERC working group involved with regional standards development).

The standard drafting team (SDT) also considered the following additional issues that were not completely captured but were stated or referenced in the above materials.

1. Modify PRC-002-1 to remove the Regional Reliability Organization (RRO) in the applicability and eliminate the reference to the RRO in PRC-018-1.
2. Create continent wide requirements applicable to Transmission Owners and Generation Owners.
3. The new standard (PRC-002-2) is being proposed based on the requirements of the existing PRC-002-1 and PRC-018-1 standards and a recommendation for replacing both of these existing standards is being proposed. The requirements in PRC-018-1 are being incorporated into PRC-002-2 with the exception of the maintenance and testing requirements in PRC-018-1.
4. Satisfy the standards procedure requirement for five-year review of the standards.

Key Issues Deliberated by the SDT:

In drafting the first version of this standard, the SDT considered the following issues:

1. The SDT decided to develop requirements for functionality for Disturbance data recording, rather than develop equipment requirements. The team focused on the "what" instead of the "how" i.e. not prescriptive.
2. The Disturbance data requirements are focused upon
   a. Sequence of events
   b. Faults
   c. Dynamic disturbances

   The requirements can be met by a variety of equipment.
3. 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 or Regional Reliability Organizations, while working with respective Transmission Owners and Generator Owners.
4. 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 required locations;
   c. Specific quantities to be monitored for required equipment; and
   d. Technical parameters to ensure adequate data to analyze a Disturbance
5. The SDT recommends that the maintenance and testing requirements for disturbance monitoring equipment be excluded from this (PRC-002-2) standard, because PRC-002-2 focuses on recording of Disturbance data and does not focus on the equipment that is used to record the data. The parties responsible for recording the data, namely Transmission Owners (TOs) and Generator Owners (GOs), can use any equipment as long as the equipment can record the specific Disturbance data at the required locations. This provides flexibility to the TOs and GOs to use various types of equipment such as relays, digital fault recorders, phasor monitoring units, swing recorders, etc. Since a multitude of equipment can be used to meet the requirements contained in this standard, the DM SDT does not have the expertise to develop an all encompassing set of maintenance/testing requirements.

   It is DM SDT's belief that the type of equipment that will be used by TOs and GOs to record Disturbance data will be similar to the protection and control system equipment. Therefore, NERC should consider finding another project that is more suitable to capture these requirements or create a SAR for these requirements.
6. The SDT decided to post the first version of this standard without compliance elements (VRFs, VSLs, etc.) to focus attention on the alone.
7. The criterion 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.

8. The SDT used the following IEEE definition 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.

The comment form includes questions to help in finalizing the development of the standard prior to balloting. For questions where you agree with the SDT, please state that you agree and if available, please provide supporting documentation. If you disagree with the SDT, please explain why you disagree and provide data to support your position. To improve the standard, the SDT would encourage responses to as many of these questions as you can answer.

The Disturbance Monitoring Standard Drafting Team would like to receive industry comments on this group of standards. Accordingly, we request that you return this form by **March 18, 2009**

Requirements to be Included in the Revised Standard

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?

☐ Yes

☐ No

Comments:

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?

☐ Yes

☐ No

Comments:

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?

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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

☐ Yes

☐ No

Comments:

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

☐ Yes

☐ No

Comments:

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

☐ Yes

☐ No

Comments:

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.

☐ Yes

☐ No

Comments:

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?

☐ Yes

☐ No

Comments:

PRC-002-1 and PRC-018-1 Mapping to Proposed NERC Reliability Standard PRC-002-02

Mapping of Standard's Introduction Sections of BOT Approved PRC-002-1 to Proposed PRC-002-2		
Standard PRC-002-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
2. Number: PRC-002-1	Proposed standard will replace both PRC-002-1 and PRC-018-1	**2. Number:** PRC-002-2
1. Title: Define Regional Disturbance Monitoring and Reporting Requirements	Regional applicability is eliminated and functional entity responsibility is defined	**1. Title:** Disturbance Monitoring and Reporting Requirements
3. Purpose: Ensure that Regional Reliability Organizations establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of Disturbance data to facilitate analyses of events and verify system models.	Regional applicability is eliminated and functional entity responsibility is defined. In addition, proposed requirements now emphasize "function" and not the equipment.	**3. Purpose:** To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES).
4. Applicability **4.1.** Regional Reliability Organization.	Regional applicability is eliminated and functional entity responsibility is defined.	**4. Applicability:** **4.1** Transmission Owners with Substations having Facilities rated at 200 kV or above **4.2** Generator Owners with any one of the following and connected to the transmission system at 200 kV or above: • Generating plants having a single generating unit of 500 MVA or higher nameplate rating • Generating plants with an aggregate plant total nameplate capacity of 1500 MVA or higher

PRC-002-1 and PRC-018-1 Mapping to Proposed NERC Reliability Standard PRC-002-02

<table>
<tr><th colspan="3">Mapping of Requirements Specific to Sequence of Events from BOT Approved PRC-002-1 to Proposed PRC-002-2</th></tr>
<tr><th>Standard PRC-002-1
NERC Board Approved</th><th>Comment</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td>R1: The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:</td><td>Regional applicability for sequence of event recording inferred in current R1 is eliminated and functional entity responsibility is defined in proposed R1, R2 & R3.

In addition proposed requirements now emphasize “function’ as stated in proposed R1, R2 & R3, not the equipment as stated in current R1.</td><td rowspan="3">R1. Each Transmission Owner shall record (or have a process in place to derive) the Sequence of Events data for changes in circuit breaker position (open/close) for each of its circuit breakers operated at 200 kV and above at each Substation that meets the following criteria:
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.
R1.2. Connected at 200 kV or above through generating unit step up transformer(s) (GSU(s)) to a generating plant having either a single generating unit of 500 MVA or higher nameplate rating, or through a GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher.
R2. Each Generator Owner shall record (or have a process in place to derive) the Sequence of Events data for changes in circuit breaker position (open/close) for its equipment identified in Table 2-1:
<table>
<tr><th colspan="2">Table 2-1: Generator Owner’s Requirement R2 for Sequence of Events Data</th></tr>
<tr><th>Location</th><th>Equipment</th></tr>
<tr><td>Each generating plant having either a single generating unit with a nameplate rating of 500 MVA or higher, and connected to the transmission system at 200 kV and above</td><td>Each generator output circuit breaker, including low side breakers</td></tr>
<tr><td>Each generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher, and connected to the transmission system at 200 kV and above</td><td>Each generator output circuit breaker, including low side breakers</td></tr>
<tr><td>Each Substation connected at 200 kV or</td><td>Each circuit breaker 200 kV and</td></tr>
</table></td></tr>
<tr><td>R1.1: Location, monitoring and recording requirements, including the following:</td><td>Current R1.1 recording requirements are covered by proposed R1, R2 & R3. (location & monitoring are covered in current sub-requirements)</td></tr>
<tr><td>R1.1.1: Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).</td><td>Location criteria stated in current R1.1.1 are covered as part of proposed R1 text & R2 in proposed table 2-1 under the “Location” heading.</td></tr>
</table>

PRC-002-1 and PRC-018-1 Mapping to Proposed NERC Reliability Standard PRC-002-02

<table>
<tr><th colspan="3">Mapping of Requirements Specific to Sequence of Events from BOT Approved PRC-002-1 to Proposed PRC-002-2</th></tr>
<tr><th>Standard PRC-002-1
NERC Board Approved</th><th>Comment</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td>R1.1.2: Devices to be monitored</td><td>Monitored devices stated in current R1.1.2 are covered as part of proposed R1 text & R2 in proposed table 2-1 under the heading “Equipment”.</td><td><table><tr><td>above through GSU(s) to a generating plant having a single generating unit with a nameplate rating of 500 MVA or higher</td><td>above</td></tr><tr><td>Each Substation at 200 kV or above connected through GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher</td><td>Each circuit breaker 200 kV and above</td></tr></table>
R3. Each Transmission Owner and Generator Owner 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) for each of its circuit breakers specified in Requirements R1 and R2.</td></tr>
</table>

<table>
<tr><th colspan="3">Mapping of Requirements Specific to Fault Recording from BOT Approved PRC-002-1 to Proposed PRC-002-2</th></tr>
<tr><th>Standard PRC-002-1
NERC Board Approved</th><th>Comment</th><th>Proposed Standard PRC-002-2</th></tr>
<tr>
<td>R2. The Regional Reliability Organization shall establish the following installation requirements for fault recording:</td>
<td>Regional applicability for fault recording inferred in current R2 is eliminated and functional entity responsibility is defined in proposed R4, R5 & R6.

In addition proposed requirements now emphasize “function’ as stated in proposed R4, R5 & R6, not the equipment as stated in current R2.</td>
<td rowspan="3">R4. Each Transmission Owner shall record (or have a process in place to derive) the following Fault Recording data for its equipment identified in Table 4-1:
R4.1. The three phase to neutral voltages on each monitored line or bus as follows:
On ring buses, the voltages of bus sections connected to transmission lines
On breaker-and-a-half arrangements, the outer bus voltages, or the individual line voltages
On straight buses, common bus voltages or the individual line voltages
R4.2. The three phase currents and the residual or neutral currents of each monitored line and transformer.
<table>
<tr><th colspan="2">Table 4-1: Transmission Owner’s Requirement R4 for Fault Recording Data</th></tr>
<tr><th>Location</th><th>Equipment</th></tr>
<tr><td>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
Each Substation connected at 200 kV or above through generating unit step up transformer(s) to a generating plant having a single generating unit of 500 MVA or higher nameplate rating
Each Substation connected at 200</td>
<td>Each transmission line operated at 200 kV or above that does not have fault data recorded at its remote terminal
Each transmission bus operated at 200 kV or above
Each transformer having low-side operating voltage of 200 kV or above</td></tr>
</table></td>
</tr>
<tr>
<td>R2.1. Location, monitoring and recording requirements, including the following:</td>
<td>Current R2.1 details contained in sub-requirements R2.1.1, R2.1.2 & R2.1.3 are covered by proposed R4, R5 & R6 and associated sub-requirements.</td>
</tr>
<tr>
<td>R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).</td>
<td>Location criteria stated in current R2.1.1 is covered as part of proposed R4 & R5 in proposed Table 4-1 and 5-1 under the “Location” heading.</td>
</tr>
</table>

Mapping of Requirements Specific to Fault Recording from BOT Approved PRC-002-1 to Proposed PRC-002-2		
Standard PRC-002-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
		kV or above through generating unit step up transformer(s) to an aggregate plant with a total nameplate capacity of 1500 MVA or higher
R2.1.2. Elements to be monitored at each location.	Monitored devices stated in **current R2.1.2** is covered as part of **proposed R4 & R5** in proposed **Table 4-1 and 5-1** under the heading "Equipment".	**R5.** Each Generator Owner shall record (or have a process in place to derive) the following Fault Recording data for its equipment identified in Table 5-1:
R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: **R2.1.3.1.** Three phase to neutral voltages. **R2.1.3.2.** Three phase currents and neutral currents. **R2.1.3.3.** Polarizing currents and voltages, if used.	**Current R2.1.3 & sub-requirements R2.1.3.1 & R2.1.3.2** are duplicated as sub-requirements in **proposed R4 & R5**. **Current sub-requirement R2.1.3.3** is not proposed because the quantity is not useful for fault analysis	**R5.1.** The three phase to neutral voltages or phase to phase voltages on Generator Step-up Transformers (GSU(s)) from the high voltage side or low voltage side of the GSU, or from the generator bus. **R5.2.** The three phase currents of GSU(s) from the high voltage side or low voltage side of the GSU, or from the generator bus **R5.3.** The neutral current of wye connected GSU(s) high voltage windings. **R5.4.** The three phase to neutral voltages on each monitored line or bus as follows: • On ring buses, the voltages of bus sections connected to transmission lines • On breaker-and-a-half arrangements, the outer bus voltages, or the individual line voltages • On straight buses, common bus voltages or the individual line voltages
R2.1.3.4. Frequency. **R2.1.3.5.** Megawatts and megavars.	**Current R2.1.3.4 & R2.1.3.5** are not being proposed since these quantities are not typically required for fault analysis and can be derived from the specified quantities of voltage and current if necessary for the analysis.	**R5.5.** The three phase currents and the residual or neutral currents of each monitored line and transformer.

<table>
<tr><th colspan="3">Mapping of Requirements Specific to Fault Recording from BOT Approved PRC-002-1 to Proposed PRC-002-2</th></tr>
<tr><th>Standard PRC-002-1
NERC Board Approved</th><th>Comment</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><th colspan="2">Table 5-1: Generator Owner’s Requirement R5 for Fault Recording Data</th></tr>
<tr><th>Location</th><th>Equipment</th></tr>
<tr><td>Each generating plant having either a single generating unit with a nameplate rating of 500 MVA or higher, and connected to the transmission system at 200 kV and above
Each generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher, and connected to the transmission system at 200 kV and above</td><td>Each GSU with a high side of 200 kV and above</td></tr>
<tr><td>Each Substation connected at 200 kV or above through GSU(s) to a generating plant having a single generating unit with a nameplate rating of 500 MVA or higher
Each Substation at 200 kV or above connected through GSU(s) to a generating plant with an aggregate plant total nameplate capacity of 1500 MVA or higher</td><td>• Each transmission line operated at 200 kV or above that does not have fault data recorded d at its remote terminal
• Each bus operated at 200 kV or above
• Each transformer having low-side operating voltage of 200 kV or above</td></tr>
</table>
</td></tr>
<tr><td>R2.2. Technical requirements, including the following:
R2.2.1. Recording duration requirements.
R2.2.2. Minimum sampling</td><td>Current R2.2, R2.2.1 & R2.2.2 are defined in the sub-requirements as part of proposed R6.</td><td>R6. Each Transmission Owner and Generator Owner shall have Fault Recording data for its equipment identified in Requirements R4 and R5 that conforms to the following:</td></tr>
</table>

Mapping of Requirements Specific to Fault Recording from BOT Approved PRC-002-1 to Proposed PRC-002-2		
Standard PRC-002-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
rate of 16 samples per cycle. **R2.2.3.** Event triggering requirements	 **Current R2.2.3,** trigger requirements, are not proposed due to the absence of industry-wide practices and the variations of established practices in different regions and locations. Therefore, it is not appropriate to define continental requirements and force those requirements on various regions or companies.	**R6.1.** A single record or multiple records that include the following: • A pre trigger record length of at least two cycles and a post trigger record length of at least 50 cycles OR • At least two cycles of the pre trigger event; the first three cycles of an event; and the final cycle of an event **R.6.2** A minimum recording rate of 16 samples per cycle.

Mapping of Requirements Specific to Dynamic Disturbance Recording from BOT Approved PRC-002-1 to Proposed PRC-002-2		
Standard PRC-002-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
R3. The Regional Reliability Organization shall establish the following installation requirements for dynamic Disturbance recording: **R3.1**. Location, monitoring and recording requirements including the following: **R3.1.1**. Criteria for equipment location giving consideration to the following: - Site(s) in or near major load centers - Site(s) in or near major generation clusters	Regional applicability for dynamic Disturbance recording inferred in **current R3** is eliminated and functional entity responsibility is defined in **proposed R7, R8, R9, R10, & R11.**. In addition proposed requirements now emphasize “function’ as stated in **proposed R7, R8, R9, R10, & R11** not the equipment as stated in **current R3**. **Current R3.1** details contained in sub-requirements R3.1.1, R3.1.2 & R3.1.3 are covered by **proposed R7, R8, R9**, **R10, & R11** and associated sub-requirements. Location criteria stated in **current R3.1.1** is covered as part of **proposed R7 & R8** text. Specific measureable	**R7.** 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, then for each Substation having a total of seven or more transmission lines connected at 200 kV or above, the Transmission Owner shall record (or have a process in place to derive) the following DDR data: **R7.1.** At least one phase-to-neutral voltage at each voltage level of 200 kV and above **R7.2.** Frequency (at least one at the required Substation) **R7.3.** At least one phase current (on the same phase and at the same voltage as the voltage monitored in R7.1 above) (for each line operated at 200 kV and above) **R7.4.** Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis (for each line operated at 200 kV and above) **R8.** Each Generator Owner shall record (or have a process in place to derive) the following DDR data at each of its generating plants with an aggregate nameplate rating of 1500 MVA or higher for each GSU that has a transformer high side connected at 200 kV or above: **R8.1.** At least one phase-to-neutral voltage or one phase-to-phase voltage at either the GSU’s high side or low side voltage level, or the generator bus voltage. **R8.2.** Frequency (at least one at the required Substation) **R8.3.** At least one phase current (on the same phase and at the same voltage as the voltage monitored in R8.1 above) or two phase currents for phase-to-phase voltages for each GSU. **R8.4.** Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis (per each monitored element) for each GSU.

Mapping of Requirements Specific to Dynamic Disturbance Recording from BOT Approved PRC-002-1 to Proposed PRC-002-2		
Standard PRC-002-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
- Site(s) in or near major voltage sensitive areas - Site(s) on both sides of major transmission interfaces - A major transmission junction - Elements associated with Interconnection Reliability Operating Limits - Major EHV interconnections between control areas - Coordination with neighboring regions within the interconnection	locations are stated.	
R3.1.2. Elements and number of phases to be monitored at each location.	Monitored devices stated in **current R3.1.2** are covered as part of **proposed R7 & R8** text. Number of phases to be monitored is not proposed however monitoring must be sufficient to derive required data.	
R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:	**Current R3.1.3 & sub-requirements R3.1.3.1 & R2.1.3.3** are specified as sub-requirements in **proposed R7**	

Mapping of Requirements Specific to Dynamic Disturbance Recording from BOT Approved PRC-002-1 to Proposed PRC-002-2		
Standard PRC-002-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. **R3.2**. Technical requirements, including the following: **R3.2.1**. Capability for continuous recording for devices installed after January 1, 2009. **R3.2.2**. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	**& R8**. **Current R3.2, R3.2.1 & R3.2.2** are defined along with additional requirements in the sub-requirements as part of **proposed R9**.	**R9.** Each Transmission Owner and Generator Owner that has DDR devices (to meet Requirement R7 or R8) shall manage its DDR data in accordance with the following technical specifications: **R9.1.** Use the same phase for voltage and current recordings. **R9.2.** Collect at least 960 samples per second to calculate RMS electrical quantities. **R9.3.** Store calculated RMS values of electrical quantities at a rate of at least 6 times per second. **R10.** Each Transmission Owner and Generator Owner that installs a DDR device after January 1, 2011 to meet Requirements R7, R8 and R9 shall install a device that is capable of continuous recording. **R11.** Each Transmission Owner and Generator Owner that has DDR devices (to meet Requirements R7, R8 and R9) that do not have continuous recording capability shall set its devices to trigger and record according to the following: **R11.1.** For rate-of-change of frequency. **R11.2.** For oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. **R11.3.** Set data record lengths at a minimum of three minutes.

Mapping of Other Disturbance Monitoring Requirements from BOT Approved PRC-002-1 to Proposed PRC-002-2		
Standard PRC-002-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following: **R4.1**. Criteria for events that require the collection of data from DMEs. **R4.2**. List of entities that must be provided with recorded Disturbance data. **R4.3**. Timetable for response to data request. **R4.4**. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE1 analysis tool. **R4.5**. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming	Regional applicability for Disturbance data reporting inferred in **current R4** is eliminated and functional entity responsibility is defined in **proposed R12 &, R13 & compliance section D paragraphs 1.3.1, 1.3.2 & 1.5.1** **Current R4.1** is proposed to be replaced by **proposed compliance section D paragraphs 1.5.1 and 1st bullet under 1.5.1.** **Current R4.2 & R4.3** are covered by the **proposed compliance section D paragraphs 1.5.1 and 1st bullet under 1.5.1.** **Current R4.4** is covered by the **proposed compliance section D, 2nd bullet under 1.5.1.** **Current R4.5** is covered by the **proposed compliance section D, 4th bullet under 1.5.1.**	**R12.** *MAPPED TO PRC-018-1 Requirement R1 – See below.* **R13.** *MAPPED TO PRC-018-1 Requirement R1.2 – See below.* **Compliance Section D** **1.5. Additional Compliance Information** **1.5.1** Each Transmission Owner and Generator Owner shall meet all of the following criteria when reporting Sequence of Event, Fault Recording , and Dynamic Disturbance Recording data to the Regional Entity or the Reliability Coordinator or NERC: • All Sequence of Event, Fault Recording, and Dynamic Disturbance Recording data shall be provided to the Regional Entity, Reliability Coordinator, or NERC within 30 calendar days of a request, • All Fault Recording and Dynamic Disturbance Recording data shall be in a format such that any software system capable of viewing and analyzing COMTRADE (IEEE Std. C37.111-1999 or successor) files may be used to process and evaluate the data, • All known delays in interposing relays shall be reported along with the SOE data, • All data files shall be named in conformance with IEEE C37.232-2007, or its successor, Recommended Practice for Naming Time Sequence Data Files.

PRC-002-1 and PRC-018-1 Mapping to Proposed NERC Reliability Standard PRC-002-02

Mapping of Other Disturbance Monitoring Requirements from BOT Approved PRC-002-1 to Proposed PRC-002-2		
Standard PRC-002-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
Time Sequence Data Files2. **R4.6**. Data content requirements and guidelines.	**Current R4.6** is covered by the **proposed compliance section D, 3rd bullet under 1.5.1.**	
R5. The Regional reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting of the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.	Since regional applicability is eliminated and functional entity responsibility is defined this existing requirement has been removed.	
R6. The Regional Reliability Organization shall periodically (at least every five years) review, update and approve its Regional requirements for Disturbance monitoring and reporting.	Since regional applicability is eliminated and functional entity responsibility is defined this existing requirement has been removed.	
		Compliance section D paragraphs **1.3.1** and **1.3.2** MAPPED TO PRC-018-1 BELOW

Mapping of Standard's Introduction Sections of BOT Approved PRC-018-1 to Proposed PRC-002-2		
Standard PRC-018-1 **NERC Board Approved**	**Comment**	**Proposed Standard PRC-002-2**
2. Number: PRC-018-1	Proposed standard will replace both PRC-002-1 and PRC-018-1	**2. Number:** PRC-002-2
1. Title: Disturbance Monitoring Equipment Installation and Data Reporting	Proposed requirements now emphasize "function' and data capture or derivation and not equipment.	**1. Title:** Disturbance Monitoring and Reporting Requirements
3. Purpose: Ensure that Disturbance Monitoring Equipment (DME) is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.	The proposed requirements now emphasize "function' and not the equipment. In addition, regional applicability is eliminated.	**3. Purpose:** To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES).
4. Applicability: **4.1.** Transmission Owners **4.2.** Generator Owners	Further defined the applicability.	**4. Applicability:** **4.1** Transmission Owners with Substations having Facilities rated at 200 kV or above **4.2** Generator Owners with any one of the following and connected to the transmission system at 200 kV or above: • Generating plants having a single generating unit of 500 MVA or higher nameplate rating • Generating plants with an aggregate plant total nameplate capacity of 1500 MVA or higher

PRC-002-1 and PRC-018-1 Mapping to Proposed NERC Reliability Standard PRC-002-02

Mapping of Standard's Requirements from BOT Approved PRC-018-1 to Proposed PRC-002-2		
Standard PRC-018-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:	Regional applicability is eliminated and functional entity responsibility is defined within proposed requirements.	**R1 through R11**. MAPPED TO PRC-002-1 ABOVE **R12.** Each Transmission Owner and Generator Owner shall synchronize all of its Sequence of Event, Fault Recording, and DDR functions to within +/- 2 milliseconds of Universal Coordinated Time (UTC) with the associated hour offset. **R13.** Each Transmission Owner and Generator Owner shall have all recorded Sequence of Event, Fault Recording, and DDR data available (locally or remotely) for 10 calendar days after a Disturbance.
R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)	**Current R1.1** is covered by **proposed R10**.	
R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days.	**Current R1.2** is covered by **proposed R11**. SEE MAPPING TO **CURRENT R5** BELOW	COMPLIANCE SECTION D PARAGRAPH **1.5** MAPPED TO PRC-002-1 ABOVE

PRC-002-1 and PRC-018-1 Mapping to Proposed NERC Reliability Standard PRC-002-02

Mapping of Standard's Requirements from BOT Approved PRC-018-1 to Proposed PRC-002-2		
Standard PRC-018-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).	Regional applicability is eliminated and functional entity responsibility is defined within proposed requirements.	GENERALLY MAPPED TO ALL PROPOSED REQUIREMENTS
R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): **R3.1**. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). **R3.2**. Make and model of equipment. **R3.3**. Installation location. **R3.4.** Operational status. **R3.5**. Date last tested. **R3.6**. Monitored elements, such as transmission circuit, bus section, etc.	Regional applicability is eliminated and functional entity responsibility is defined within **proposed compliance section D paragraph 1.3.2**. **Current R3.1, R3.2 & R3.3** are covered by **compliance section D, 1st, 2nd, and 3rd bullets under 1.3.2.** **Current R3.4 & R3.5** were not proposed due to changing status and lack of value added for analysis. **Current R3.6** is covered by **compliance section D, 4th bullet under 1.3.2.**	**Compliance Section D** **1.3. Data Retention** **1.3.2** Each Transmission Owner and Generator Owner shall each maintain, and report to the Regional Entity, Reliability Coordinator or NERC within 30 calendar days of a request, the following information for Sequence of Event, Fault Recording, and Dynamic Disturbance Recording data: • Location • Make and model of equipment • Type of data source (Sequence of Events, Fault Recording, or Dynamic Disturbance Recording). • Monitored elements, such as transmission circuit, bus section, circuit breakers, etc.

PRC-002-1 and PRC-018-1 Mapping to Proposed NERC Reliability Standard PRC-002-02

Mapping of Standard's Requirements from BOT Approved PRC-018-1 to Proposed PRC-002-2		
Standard PRC-018-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc. **R3.8**. Monitored electrical quantities, such as voltage, current, etc.	**Current R3.7 & R3.8** are already proposed as requirements making such a database unnecessary.	
R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).	Regional applicability is eliminated and functional entity responsibility is defined within proposed requirements.	GENERALLY MAPPED TO ALL PROPOSED REQUIREMENTS
R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	**Current R5** is covered by **proposed compliance section D paragraph 1.3.1.**	**Compliance Section D** **1.3. Data Retention** **1.3.1** Each Transmission Owner and Generator Owner shall retain all data provided to the Regional Entity, Reliability Coordinator or NERC for at least three years following the event.

PRC-002-1 and PRC-018-1 Mapping to Proposed NERC Reliability Standard PRC-002-02

Mapping of Standard's Requirements from BOT Approved PRC-018-1 to Proposed PRC-002-2		
Standard PRC-018-1 NERC Board Approved	**Comment**	**Proposed Standard PRC-002-2**
R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes: **R6.1**. Maintenance and testing intervals and their basis. **R6.2**. Summary of maintenance and testing procedures.	**Current R6 & sub-requirements** are proposed to be transferred to Project 2007-17 Protection System Maintenance and Testing	

Implementation Plan for PRC-002-02

Background

In developing the implementation plan, the Standard Drafting Team considered the following:

1. The requirements set forth in the proposed standard are more stringent than the existing requirements in the FERC approved standard PRC-018-1 and any regional requirements resulting in the implementation of PRC- 002-1.
2. The timeframe required by nuclear plants to be compliant will be dependent upon the period between refueling outages, which typically is around 24 months.
3. Any implementation plan will be impacted by the resource availability and approval processes that the Transmission Owners and Generator Owners have to go through every year.
4. PRC-018-1 as approved by FERC in June 2007 contained requirements that were to be included in Regional Reliability Organizations' (RRO) procedures, e.g. Requirement 1.1 regarding time synchronization. PRC-002-1, a fill-in-the-blank standard, contained a list of subject matter that was to be addressed in the RRO procedures in addition to the RRO procedure related requirements from PRC-018. Although not approved by FERC for monetary enforcement, PRC-002-1 was characterized as a good utility practice standard that warrants continued monitoring. In addition, some items such as time synchronization were the subject of blackout recommendations.

   The intended effective date of the PRC-002-1 requirements for the development of RRO procedures assumed that nine months from the NERC Board approval on August 2, 2006, the RRO procedures would have been issued, namely May 2007. Full compliance implementation of requirements such as time synchronization would be achieved by June 2011. The SDT proposes an effective date for requirements previously contained in PRC-018, which do not have fill-in-the-blank characteristics, such as R1.1, of 18 months following regulatory approval. In this manner, such requirements will continue to be on the same time table for full compliance implementation as intended by PRC-018-1. This includes approximate times to complete the proposed standard and obtain NERC and regulatory approval.

   All other requirements in this proposed continent wide draft standard effectively become the previous RRO fill-in-the-blank requirements. Since these requirements are not necessarily identical to any current or proposed regional procedures, the SDT believes that it is appropriate to provide the same preparatory time margin, namely four years for full compliance implementation from the time of regulatory approval, as was intended in PRC-002-1 & PRC-018-1 when issuance of an approved RRO procedure was referenced.

Effective Dates for PRC-002-2 Requirements R1 through R11

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:

    a. Each Responsible Entity shall be at least 50% compliant on monitored equipment

2. 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 four years after Board of Trustees adoption:

    a. Each Responsible Entity shall be 100% compliant on monitored equipment.

Effective Dates for PRC-002-2 Requirements R12 and R13 (PRC-018-1 R1.1 and R1.2):

1. The first day of the first calendar quarter eighteen months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter eighteen months after Board of Trustees adoption.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Three Comment Periods Open

Now available at:

http://www.nerc.com/filez/standards/Reliability_Standards_Under_Development.html

Errata for Four Reliability Standards

Errata for four Reliability Standards are posted for a 30-day comment period. The comment period is now **open until 8 p.m. EST on March 2, 2009**.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Standards_Errata.html

Background

Clean and redline versions of the following standards are posted on the project page:

1. IRO-006-4 — Reliability Coordination — Transmission Loading Relief
2. MOD-021-0 — Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts
3. PER-001-0 — Operating Personnel Responsibility and Authority
4. TPL-006-0 — Data From the Regional Reliability Organization Needed to Assess Reliability

Errata Process

In accordance with the Standards Committee's procedure for Approving Errata in an Approved Reliability Standard, if the proposed revisions are supported by stakeholders and approved by the NERC Board of Trustees, the associated standards will be corrected and posted with a new version number and submitted to governmental authorities for their approval. To reflect that there is a minor change to correct errata, the version numbers will be updated by adding a decimal point and the numeral "1" after the decimal point. For example, IRO-006-4 will be changed to IRO-006-4.1.

Proposed Standard PRC-002-2 — Disturbance Monitoring and Reporting Requirements (Project 2007-11)

The Disturbance Monitoring Standard Drafting Team (Project 2007-11) has posted its first draft of standard PRC-002-2 — Disturbance Monitoring and Reporting Requirements, a mapping document, and an implementation plan for a 45-day comment period. The comment period is now **open until 8 p.m. EDT on March 18, 2009**.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/Disturbance_Monitoring_Project_2007-11.html

Background

The purpose of this standard is to establish requirements for recording and reporting sequence of events data, fault recording data, and dynamic disturbance recording data to facilitate analysis of Disturbances. The project involves replacing "fill-in-the-blank" requirements currently assigned to the Regional Reliability Organization with continent-wide requirements that are applicable to other functional entities. This standard will replace PRC-002-1 — Define and Document Disturbance Monitoring and Equipment Requirements and PRC-018-1 — Disturbance Monitoring Equipment Installation and Data. The project also involves bringing the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure.

Revisions to Standard NUC-001-1 — Nuclear Plant Interface Coordination for Order 716 (Project 2009-08)

The Nuclear Plant Interface Coordination Standard Drafting Team (Project 2009-08) has posted its first draft of standard NUC-001-2 — Nuclear Plant Interface Coordination, an implementation plan, and a Standards Authorization Request (SAR) for a 45-day comment period. The comment period is now **open until 8 p.m. EDT on March 18, 2009**.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047. An off-line, unofficial copy of the questions listed in the comment form is posted on the project page:
http://www.nerc.com/filez/standards/Project2009-08_Nuclear_Plant_Interface_Coordination.html

Background

The Nuclear Plant Interface Coordination standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring safe nuclear plant operation and shutdown. The proposed revisions address two directives in Federal Energy Regulatory Commission (FERC) Order 716 aimed at addressing stakeholder concerns for improved clarity. Additional revisions were made to change the term “Planning Authority” to “Planning Coordinator” (to match the terminology in the latest version of the Functional Model) and to bring the compliance elements of the standard into conformance with the latest version of the ERO Rules of Procedure.

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Individual or group. (60 Responses)
Name (45 Responses)
Organization (45 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Contact Organization (15 Responses)
Question 1 (58 Responses)
Question 1 Comments (60 Responses)
Question 2 (47 Responses)
Question 2 Comments (60 Responses)
Question 3 (58 Responses)
Question 3 Comments (60 Responses)
Question 4 (56 Responses)
Question 4 Comments (60 Responses)
Question 5 (54 Responses)
Question 5.1 Comments (60 Responses)
Question 5 (53 Responses)
Question 5.2 Comments (60 Responses)
Question 5 (52 Responses)
Question 5.3 Comments (60 Responses)
Question 6 (49 Responses)
Question 6 Comments (60 Responses)
Question 7 (55 Responses)
Question 7 Comments (60 Responses)
Question 8 (52 Responses)
Question 8 Comments (60 Responses)
Question 9 (53 Responses)
Question 9 Comments (60 Responses)
Question 10 (54 Responses)
Question 10 Comments (60 Responses)
Question 11 (53 Responses)
Question 11 Comments (60 Responses)
Question 12 (51 Responses)
Question 12 Comments (60 Responses)
Question 13 (53 Responses)
Question 13 Comments (60 Responses)
Question 14 (43 Responses)
Question 4 Comments (60 Responses)
Question 15 (40 Responses)
Question 15 Comments (60 Responses)
Question 16 (53 Responses)
Question 16 Comments (60 Responses)
Question 17 (41 Responses)
Question 17 Comments (60 Responses)
Question 18 (42 Responses)
Question 18 Comments (60 Responses)

Individual
Joe Uchiyama
US Bureau of Reclamation
Yes
It is good idea to make a single document to cover all DME requirements
Yes
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.

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).
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.
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.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
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-disturbacne analysis. These values should be 20MVA/unit and 75MVA/plant.
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-transmissin system? etc.
Individual
Robert W. Cummings - Director of Evnet Analysis
NERC
Yes
Yes
Yes

They should be included in PRC-005 -- Transmission Protection System Maintenance and Testing
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.”
No
Disagree with 200 kv and above...should be 100 kv and above.
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.
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..."
Yes
No
R1.1 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.” Note the change from 3 elements to 5 elements...3 elements woudl require a significant number of new installations.
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.
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.
Yes
R7 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, 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)”
Yes
No
R7 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, 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.”
Yes
No
For reasons of consistency in the ability to cross-regional or interconnection-wide disturbance analysis, there should be no regional variances.
No
Yes
Effective Date R12-R13 For 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:"
No
Effective Date R12-R13 For 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:
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
We assumed that the question refers to the merging of Standards PRC-002-1 and PRC-018-1.
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.
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.
Yes
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.
Yes
Yes
Yes

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.
Yes
This requirement allows for the inclusion of legacy equipment. This requirement does not stipulate the recording of adequate information for analysis.
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).
Yes
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?
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.
Yes
No
No
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.
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.
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.
Individual
Jian Zhang
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.
No
To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
No
To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
No
To use a specific number may not be appropriate way. Please see the comments in Q4 for justification

No
To use a specifie number may not be approperiate way. Please see the comments in Q4 for justification.
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 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.
Individual
Joe White
Grant County PUD
Yes
Yes
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.
Yes
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.....
Yes
Yes
Yes

Yes
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.....
Yes
Yes
No
Yes
Yes
Individual
Jeremiah Stevens
NYISO
Yes
Yes
Yes
Yes
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.
Yes
Yes
Yes
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.
Yes
Yes, this sounds good, but we don't understand how one could record the first 3 cycles and final cycle of an event.
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 genertator owner. Change the requirement such that the substation owner needs to monitor this.
Yes
Yes
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.
Yes
No
No
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 R4.2 R5.5 there is an extra "d" in "...fault data recorded d at it's remote terminal"
Yes
Yes
Individual
Gary Preslan/Bill Middaugh
Tri-State Generation and Transmission Association
Yes
Yes
Yes
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.
Yes
Yes
Yes
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?
Yes
We would like to ensure that no separate Sequence of Events Recorder is required if the data can retrieved from archived SCADA logs.
Yes
How is the final cycle of an event determined?
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 ensure that sufficient quantities are available to perform any required calculations.
Yes
Yes
Yes
No
Data should be retained longer than 10 calendar days. We would suggest 60 days as a minimum.
No
No
No
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?
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.
Group
IRC Standards Review Committee
Ben Li
IESO
Yes

Yes
Yes
The SRC agrees with the proposal to exclude maintenance and testing from this standard.
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."
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."
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."
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.
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.
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.
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.
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.
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).
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.
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.
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.
No
No
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.
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.
No
Individual
Russell A. Noble
Cowlitz County PUD
Yes
A single standard addressing disturbance monitoring is GREATLY appreciated. This will simplify compliance efforts.
Yes

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 for PRC-002-2 work on the M&T standard.
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.
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.
Yes
Again, I feel the burden of proof should be on those who would argue for more stringent criteria.
Yes
Again, I feel the burden of proof should be on those who would argue for more stringent criteria.
Yes
Yes
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.
Yes
Yes
I find the original verbiage of R7 confusing without the clarifying statement above. I would consider rewording R7.
Yes
Yes
Yes
No
Question 14 Comments:
No
No
Typo above, it is 16.
Yes
Question 17 Comments: This standard as written will not apply to Cowlitz and therefore will not present a burden.

Yes
Individual
Adam Menendez
Portland General Electric
Yes
Yes
Yes
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?
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?
Yes
Yes
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 requirment be for substations with five or more lines operated at 200 kV or above.
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"?
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.
Yes
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?
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 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.
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.
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.
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.
Individual
Dania J. Colon
Progress Energy Florida
Yes
Yes
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.
Yes
Yes
Yes
Yes
Yes
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 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 only include the >200kV circuit breaker SER data.
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)".
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.
Yes
Yes
Yes
Yes
No
No
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 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.
Yes
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.
Individual
Catherine Koch
Puget Sound Energy
Yes

Yes
Yes
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?
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?
Yes
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.
Yes
The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
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.
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?
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.
Yes
The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
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.
The Effective date information is unclear for the 50% and 100% compliance requirements.
Individual
Lance Irwin
Schneider Electric
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
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?
Yes
No
No
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?
Yes
Yes
Group

SPP System Protection and Control Working Group
Shawn Jacobs
Southwest Power Pool
Yes
Please clarify the term "entity specific requirements" in Question #1.
Yes
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.
Yes
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.
Yes
Yes
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.
Yes
No
Recommend to change "first three cycles" to "first six cycles". Six cycles will give you the relay time plus the breaker time.
Yes
Yes
Yes
No
1) Please clarify R 10 and R 11 with respect to date (January 1, 2011). One suggestion is to have R11 listed before R10. 2) Specify the actual trigger value in R 11.1
Yes
1. Please clarify the definition of Disturbance. Is it according to Table 1 in EOP-004-1?
No
No
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?
Yes

1) Please clarify the effective dates section stating when each entity needs to be 50% and 100% compliant respectively.
Yes
Individual
Dan Rochester
Independent Electricity System Operator
Yes
Yes
Yes
Yes
Yes
Yes
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.
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.
Yes
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.
No
Please see our comments on R6, above.

Yes
Yes
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.
Yes
No
No
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 conditions or events.
Yes
Yes
Individual
James H. Sorrels, Jr.
American Electric Power
Yes
Yes
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.
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.
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.
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.
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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.
Yes
Yes
Yes
Yes
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.
Yes
Yes
Yes
No
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.

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.
Yes
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.
Individual
Michael Sonnelitter
NextEra Energy Resources (formerly FPL Energy)
Yes
Yes
Yes
Yes
No
In light of the same argument made above, it is recommended that the single generating unit level be changed to "750MVA or higher".
No
In light of the same argument made above, it is recommended that the single generating unit level be changed to "750MVA or higher".
Yes
Yes
Yes
Yes
No
Section R4.1 Recommend changing the first bullet to read “On ring buses, the voltages of bus sections connected to transmission lines, or the individual line voltages.” Section R4.2 Recommend 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 4-1 Recommend changing the single generating unit level to “750MVA or higher” to avoid unnecessary Fault Recording Equipment installations. Section R5.1 Recommend 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 R5.2 Recommend 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 R5.4 Recommend changing the first bullet to read “On ring buses, the voltages of bus sections connected to transmission lines, or the individual line voltages.” Section R5.5 Recommend 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 5-1 Recommend changing the single generating unit level to “750MVA or higher” to avoid unnecessary Fault Recording Equipment installations.
Yes
Yes
Yes
Yes
No
No
No
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.
Yes
Individual
Manuel Couto
National Grid
Yes
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 interpertation.

Individual
Kris Manchur
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No

No
No
Yes
Yes
We agree with the IEEE definition.
Individual
John Gyrath
Exelon Generation LLC
Yes
Yes
Yes
Yes
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.
Yes
Yes
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.
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.
Yes
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 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.
Yes
Yes
Yes
Yes
No
No
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 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.
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 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.
Yes

Individual
Scott Helbing
NV Energy
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
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.
Yes
As stated previously, the DDR data format differs from region to region and should be standardized.
No
No
Yes
Yes
Individual
Dave Szulczewski

DTE Energy/Detroit Edison
Yes
Yes
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.
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.
No
Please see comment for 5.1.
No
Recommend that generator low side breaker monitoring should be excluded or optional if the high side breaker connected to the system is monitored.
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?
Yes
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.
No
Please see comments for 9.
No
Will regional variances be included in this standard?
Yes
When will violation severity levels be added?
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.
Yes
A definition is warranted, but the IEEE definition doesn't cover all the configurations that exist.
Individual
Dale Fredrickson
Wisconsin Electric
Yes

Yes
Yes
Yes
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.
Yes
Yes
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.
Yes
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?
Yes
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.
No
The intent of R13 is not clear to us. This seems to be a data retention requirement.
No

No
Yes
Group
Members of of the WECC Disturbance Monitoring Work Group
Donald Davies
WECC
Yes
Yes
Yes
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?
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?
Yes
Yes
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.
Yes
The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
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.
Yes
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?
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.
Yes
The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
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.
The Effective date information is unclear for the 50% and 100% compliance requirements.
Individual
Jack Soehren
ITCTransmission, METC
Yes
Yes
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.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
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.
Yes
No
No
No
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".
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.
Individual
Alan Gale
City of Tallahassee (TAL)
Yes
Any time we can combine similar requirements into the same standard we are better off.
No
urrent "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!
Yes
It would be ideal if ALL Maintenance and Testing requirements were in one standard!
Yes
I agree with the approach. This approach makes it clear where it is needed, except as noted below.
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.
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.
Yes
Yes
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.

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?
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".
Yes
See concern in Q9 for R4.1, Bullet 1.
Yes
Same concern with "plant" vs. "site".
No expertise to provide input.
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.
No
No
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.
Yes
Yes
Group
Southern Company - Transmission
Jim Busbin
Southern Company Services, Inc.
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 to an overall NERC defined methodology. In the absense of a NERC defined methodology, a SAR should be introduced to produce one.
Yes
No further comment.
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.
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.
Yes
No further comment.
Yes
No further comment.
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.
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.
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.
Yes
No further comment.
Yes
No further comment.
Yes
Southern Company restates its objection to the use of arbitrary location requirements.
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 locate disturbance monitoring equipment should be derived from stability studies (angular, voltage. etc) of the electric grid in accordance with a NERC defined methodology.
Yes
Southern Company supports the comments submitted by the SERC PCS for this question.
Yes
No further comment.
No
No further comment.
No
No further comment.
No
No further comment.
Yes
Southern Company supports the comments submitted by the SERC PCS for this question.
Yes
Southern Company supports the proposed definition of "Substation."

Individual
Alvin C. Depew
PHI (PEPCO Holdings Inc.)
Yes
No need for different standards to cover DM.
Yes
Yes
Yes
Yes
Yes
Yes
No
The time should be listed as 1/4 cycle, since many relays specs indiacte 1/4 cycle for this requirement.
Yes
Yes
Yes
FR trigering requirements are not addressed.
Yes
Yes
Yes
It should be clairified 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.
Yes
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.
No
No
Yes
Yes
Individual
Richard Salgo
NV Energy (fka Sierra Pacific Resources)

Yes
Yes
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.
Yes
Yes
These MVA and voltage levels appear to be appropriate for the intent of this Standard.
Yes
These MVA and voltage levels appear to be appropriate for the intent of this Standard.
Yes
Yes
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".
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?
No
Table 4-1 should also be modified to identify Substations containing any combination of five or more elements. See response to Q7 previous.
Yes
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.
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 sampels 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.
Yes
No

No
No
Yes
Individual
John Hernandez
Salt River Project
Yes
Yes
Yes
Yes
Yes
Yes
Yes
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.
Yes
What is the definition of the "final cycle of an event"?
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.
Yes
Yes
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 requirment eliminates the use of this adequate equipment.
Yes
The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.

Group
SERC Engineering Committee Planning Standards Subcommittee
Phillip R. Kleckley
South Carolina Electric & Gas
Yes
Yes
Yes
Yes
Yes
These values seem to be in the appropriate range.
Yes
These values seem to be in the appropriate range.
Yes
These values seem to be in the appropriate range.
Yes
Yes
No
It is not clear why there are two different requirements for sampling data.
Yes
Yes
No
No
No
Yes
No
There is not sufficient misunderstanding to warrant a definition.
Individual
John F. Hauer
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.
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.)
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.
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.
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.
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.
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 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 quanitites, 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.
Individual
Jerry Blackley
Progress Energy Carolina, Inc.
Yes
Yes
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.
Yes
These requirements will create consistancy in the required locations where the regions "opinions" are not different.
Yes
Yes
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
Yes
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 only include the >200kV circuit breaker SER data.
No
Ok with first bullet under R6.1, however, the second bullet refers to "event" without a definition of what constitutes an "event".
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.
Yes
Yes
Yes
Yes
No
No
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.
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.

Yes
Individual
Roger Champagne
Hydro-Québec TransÉnergie (HQT)
Yes
We assumed that the question refers to the merging of Standards PRC-002-1 and PRC-018-1.
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.
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.
Yes
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.
No
See Q5.1 answer above.
No
See Q5.1 answer above.
Yes
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.
Yes
This requirement allows for the inclusion of legacy equipment. This requirement does not stipulate the recording of adequate information for analysis.
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).
Yes
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?
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.
Yes
No
No
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.
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.
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.

Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Yes
Yes
Yes
No
The approach needs better engineering support of the criteria.
Yes
No
Need to add clarity to the criteria and do not reference Tables for requirements.
No
Clarify criteria and remove Tables.
Yes
Individual
Steve Rueckert
WECC
Yes
I also agree with changing the fill in the blank characteristics into entity specific requirements
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?

Group
SERC Protection and Controls Sub-committee
Steve Waldrep (Co-Chair), Joe Spencer (SERC staff)
SERC Reliability Corporation
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.
Yes
Except possible impact based on protection scheme used when three phase line or bus potential are not available.
No
Prefer that M&T continue to be contained within this standard.
No
Agree with the approach given our understanding of the standard's intent. The documents wording and Tables need to be clearer and more consistent. Suggest exempting 230 kV radial lines without transmission connected generation. 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. It should be made clear that the equipment that must be monitored by a GO in Tables 2-1 and 5-1 should 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.
Yes
Yes
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
Yes
Suggest in R3, for consistency, use similar terminology to R12 (where reference is +/- 2 ms).
No
Reference comments on #4 above. Suggest in R3, for consistency, use similar terminology to R12 (where reference is +/- 2 ms).
Yes
Add to the end of the first bullet "...for the same trigger point"
Yes
Re-label heading of Table 4-1 to indicate: "...for substation equipment owned by Transmission Owner"
Yes
Refer to response in 5.3
Yes
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 (what part of the 3 minutes should be pre and post trigger?).
Yes
Yes
See comment on response #1.
No
No
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.
Yes
We agree with the IEEE definition.
Individual
Ed Davis
Entergy Services, Inc
Yes
Yes
Yes
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.
Yes
Yes
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.
Yes
Yes
Yes
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.
Yes
Agree with the criterion of adjacent station coverage consistent with comments on 5.3.
Yes
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.
Yes
No
Not as proposed, but there should be for DDR applications.
No
Yes
Seems like Section D.1.5 Additional Compliance Information should be listed as part of the requirements.
Yes
Yes
Group
PacifiCorp
Sandra Shaffer
PacifiCorp
Yes

Yes
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).
Yes
Yes
Yes
Yes
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.
Yes
Yes
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.
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.
Yes
No
No
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.
Yes
The time allowed in the draft standard appears acceptable.

Yes
Individual
Rick White
Northeast Utilities
Yes
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"?
Yes
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.
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.
Yes
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.
Yes
No
Sequence of Events requirements should include monitoring of transmission and generator circuit breaker positions and protective relay tripping for all protection groups.
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.
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).
Yes
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.
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.
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.
No
No
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.
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.
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.
Individual
Randy Schimka
San Diego Gas and Electric Co.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes

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.
Yes
Is there a definition of "the final cycle of an event"? We'd want to make sure that we understand that fully.
Yes
Agree, except for the comment made in question 7 above about changing the SOE criteria from three lines to five lines.
Yes
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.
No
The requirement in R9.2 to collect 960 samples per second seems high for the purpose of reliability.
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.
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?
Yes
Individual
Gregory Campoli
New York Independent System Operator
Yes
Yes
Yes
Yes
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
Yes
Yes

Yes
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 CB positions, protective relay tripping for all protection groups and teleprotection keying and receiving.
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.
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.
Yes
Yes
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 continous recording ability for newly installed DDRs The requirement of recorders installed after Jan 1, 2011 being able to continously record would be redundant for the NPCC which requires recorders installed after Jan 1, 2009 to be continous 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 cabability and future installations. (R11.3) Not all existing recorders have this capability. Require minimium of 3 minutes for recorders with the capability, and 60 seconds for the minimum post trigger record length for all others.

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.
No
No
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 H4 C37.118 Synchrophasor Standard revision – Working Group H11 Channel Names and Instrument Names – Working Group H10 SOE Data – Working Groups H5b (completed) and H16
Yes
Individual
Brent Ingebrigtson
E.ON U.S..
Yes
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
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

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.
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.
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.
In answering this question, E ON US would benefit from knowing the SDT's technical basis for the 4 milliseconds
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.
No
Generally, pre-trip data has more analytical value than post-trip data.
Yes
The SDT should explain the applicability of this requirement to the GO.
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.
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 lrequire 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.
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.
Group
Dominion
Jalal Babik
Dominion Resources Services, Inc
Yes
Yes

No
Prefer M&T to be contained within this standard. Do not move DME M&T to a totally new standard.
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 Owner” As 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 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.
Yes
Yes
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.
Yes
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.
Yes
Add to end of first bullet under R6.1 "...for the same trigger point"
Yes
Re-label heading of table 4-1 to indicate:"... for substation equipment owned by Transmission Owner"
Yes
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.
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 pre-trigger and post-trigger be a minimum of 1 minute each with total record at least 3 minutes
Yes
Yes
We support the 200 kV cutoff. However, some regions have indicated the 200kV threshold is not appropriate and 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
Yes
Concern that FERC standards and code of conducts, as well as some RTO/ISO rules may prohibit the GO from access to system monitoring data necessary to participate in disturbance analysis studies.
The applicabilty 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.
Yes
We suggest revising the langauge 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 requirment 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.
No
We do not belive that a defintion is warranted. However, if one is deemed necessary we agree with the use of the IEEE definition.
Group
Bonneville Power Administration
Denise Koehn
Transmission Reliability Program
Yes
Is there a purpose to the analyses proposed. How much detail is really needed?
Yes
Yes
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?
Yes
For generating stations with split interconnection voltages (some units connected below 200 kV), define how to interpret.

Yes
For generating stations with split interconnection voltages (some units connected below 200 kV), define how to interpret.
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.
No
BPA believes 2-4 second SCADA/EMS records are good enough for most events.
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.
Yes
The number of element criteria may be too stringent, change to 5 elements.
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 auxilliary (transfer) bus scheme. The number of element criteria may be too stringent, change to 5 elements.
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).
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.
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 setpoint level vs rate of change. Change R11.3 to have record length include pre-trigger event of 30 seconds to 1 minute.
Yes
No
No
Yes
No
It's too fast for a 3 year budget cycle entity.
Yes
Also supply the IEEC C37.111-1999 and C37.232-2007 referred to.
Group
FirstEnergy
Sam Ciccone
FirstEnergy Corp.
Yes

We agree that it will be beneficial to consolidate these standards into one document.
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.
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.
Yes
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.
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.
Yes
No
To allow for some flexibility and consistent with other requirements, we recommend replacing 4 ms with 1/4 cycle.
Yes
Yes
Yes
Yes
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 required to record dynamic disturbances.
Yes
Yes

No
No
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.
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".
Yes
Individual
Douglas Selin
Arizona Public Service Co.
Yes
Yes
Yes

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.
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.
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%).
Yes
This is not consistent with requirement R12 which states +/- 2 ms since within 4 ms means +/- 4.
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.
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.
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.
Yes
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.
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 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.
No
Earlier in R3 you specify +/- 4 ms
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 standard proposes.
No
Group
Transmission Owner
Silvia Parada-Fortun
Florida Power & Light
Yes
A single standard to define the installation application of DMEs makes good sense.
Yes
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.
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.
Yes
Yes
Yes
We generally agree with this, however, it needs some defining.
Yes
However, please view our comments for question 17.
Yes
Yes
We agree, however, the term "event" needs to be defined. Please provide a working definition for event.
Yes

Yes
This needs to be stated more clearly. Could you provide specific examples as part of FAQs.
Yes
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.
Yes
Please see comments for question 17.
No
No
No
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.
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.
Individual
Charles J. Jensen
JEA
Yes
Yes

Good job on mappring all the requirements!!
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 capabilites 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.
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 the fact that DDRs are covering the area and that DFRs may not be required from an additional data coverage standpoint.
Yes
Yes
Yes
There is good correlation from mulitple 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.
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.
Yes
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.
Yes
Yes
Yes
Yes

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 requriement should be easily met, but not for relay DFR equipment.
No
No
No
Yes
Yes
Individual
John Tolo
Tucson Electric Power
Yes
Yes
Yes
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?
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?
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?
Yes
Yes
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.
Yes
The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
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.
Yes
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?
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.
Yes
The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
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.
The Effective date information is unclear for the 50% and 100% compliance requirements.
Individual
Anita Lee
Alberta Electric System Operator
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
The AESO supports the IRC SRC comments to this question.
Yes

The AESO supports the IRC SRC comments to this question.
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".
No
The AESO supports the IRC SRC comments.
Yes
The AESO supports the IRC SRC comments.
Yes
No
The AESO supports the IRC SRC comments.
No
The AESO supports the IRC SRC comments.
Yes
No
Yes
No
The AESO supports the IRC SRC comments.
No
Individual
Murty Yalla
Beckwith Electric Co
Yes
Yes
Yes
Yes
No
Recommend changing it to: "The status of GSU circuit breakers and sequence of events data of protective relay 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.
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.
Yes

Yes
Yes
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 length to at least 5 sec with pre and post trigger length selectable based on the triggering mechanism.
Yes
Yes
Yes
Yes
Yes
No
No
No
Yes
Yes
Individual
Greg Rowland
Duke Energy
Yes
Yes
Yes
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.
Yes

Yes
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
Yes
Suggest in R3, for consistency, use similar terminology to R 12 (where reference is +/- 2 ms).
Yes
Yes
Yes
Yes
Yes
Yes
Yes
DDR data will overwrite after 10 days, in some instances.
No
No
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.
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.
No
We agree with the IEEE definition. We don't think that there is sufficient misunderstanding to warrant a NERC definition.
Individual
Armin Klusman
CenterPoint Energy

Yes
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.
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.
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 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.
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.
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.
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 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.
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. 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.
Individual
Alice Murdock
Xcel Energy
Yes
Yes
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.
Yes
Yes
Yes
Yes
Yes

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."
Yes
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."
Yes
Yes
Yes
Yes
No
No
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.
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.
We agree the IEEE definition is appropriate.
Individual
R. Peter Mackin, P.E.
Utility System Efficiencies, Inc.
Yes
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.)
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.
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?
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?
Yes
Yes
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.
Yes
The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
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.
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.
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?
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 caluculations?" 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.
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.
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, resampling, calculation of derived quanitites, renaming or selective deletion of signals.
The Effective date information is unclear for the 50% and 100% compliance requirements.
Group
Los Angeles Department of Water & Power
George P. Nino
Metering and Control Design Group
Yes
Yes
Yes
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.
Yes
These values appear reasonable and affect several of our generating stations.
Yes
These values appear reasonable and affect several of our generating stations.
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.
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.
No
No
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.
Yes
Individual
Dan Buchanan
British Columbia Transmission Corporation
Yes
Yes
Yes

Yes
Yes
Yes
Yes
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 requirment be for substations with five or more lines operated at 200 kV or above.
Yes
What is the definition of the "final cycle of an event"?
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.
Yes
Yes
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.
Yes
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.
Group
MRO NERC Standards Review Subcommittee
Michael Brytowski
MRO
Yes
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

Yes
Having a separate maintenance and testing standard may be easier to administrate for most utilities.
Yes
Yes
While the MRO NSRS does not disagree with the levels mentioned above, what is the technical basis for selecting those levels?
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)?
Yes
Yes
Yes
No
The first three cycles of an event and the final cycle of an event doesn't seem adequate.
Yes
Table 5-1 has a type-o - Row 2, Column 2, bullet 1 extra 'd'.
Yes
Yes
Yes
Yes
No
No
Yes
Yes
Yes
Group
PG&E System Protection
Ed Taylor
Pacific Gas and Electric Co.
Yes
Yes
Yes

Yes
The Threshold for the number of elements is too low.
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?
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?
Yes
Yes
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.
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.
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.
Yes
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?
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.
Yes
The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
No
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.
The Effective date information is unclear for the 50% and 100% compliance requirements. Also, how would this implementation plan affect the PRC-018 application?

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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 standard was 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, Mark Lauby at 609.446.9723 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

The responses and proposed changes below were developed by the previous Drafting Team prior to the Project being moved to informal development in the Fall of 2010. The suggested changes to the Standard may not reflect the vision of the current Drafting Team, but the Drafting Team has taken them into consideration while drafting in the latest version of the Standard. The Project moved to formal development in January of 2013. The Drafting Team will be holding a Webinar and Workshops to bring the industry up to speed on the Project and to obtain feedback.

In drafting the second version of this standard, the SDT considered the following issues:

The SDT decided to develop requirements for functionality for Disturbance data recording, rather than to require specific equipment. The team focused on the “what” is required rather than describing “how” it is to be done.

The Disturbance data requirements are focused on

- Sequence of events
- Faults
- Dynamic disturbances

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/pa/Stand/Resources/Documents/Appendix3AStandardsProcessesManual.pdf

Posted: May 17, 2013

The requirements can be met by a variety of equipment.

The SDT re-introduced the requirements for maintenance and testing of disturbance recording systems in the proposed standard. The SDT is proposing that the responsible entities establish and utilize a maintenance and testing program that contains specific items. Maintenance and testing requirements that are currently part of the FERC approved standard, PRC-018-1 – Disturbance Monitoring Equipment Installation and Data Reporting Requirement R6 will be replaced by the requirements in the proposed PRC-002-2.

During the first posting, the majority of commenters either suggested alternate equipment location criteria or requested technical justification for the proposal in draft 1 of the standard. In response to this feedback, the SDT conducted an analysis of short-circuit MVA data using data submitted voluntarily by several utilities. The criterion used by the SDT in selecting locations for monitoring/recording Disturbance data is based on an analysis conducted by the team in 2009-2010. Please review the technical paper posted with the standard that summarizes the analysis.

The SDT removed the proposed IEEE definition for sub-station due to comments received in the first posting. The SDT also included definitions for Disturbance Monitoring Equipment (DME), Sequence of Events (SOE) recorder, Fault Recorder (FR), and Dynamic Disturbance Recorder (DDR). The definition for DME exists in the NERC Glossary of terms but will be replaced by the proposed definitions when the proposed standard is approved.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		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	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
6.	Donald Davies	WECC	WECC	NA
7.	Kenneth Wilson	WECC	WECC	NA

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Jim Busbin	Southern Company - Transmission	X		X		X					

	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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Phillip R. Kleckley	SERC Engineering Committee Planning Standards Subcommittee			X							

	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	1	2	3	4	5	6	7	8	9	10
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				

		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

		Additional Member	Additional Organization	Region	Segment Selection
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	Industry Segment									
				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: Commenters generally agreed with the SDT proposal to retire PRC-018-1 (except for Testing and Maintenance requirements) and merge those requirements with a revision of PRC-002-1, resulting in a new standard, PRC-002-2. Commenters also agreed with the proposal to replace the "fill in the blank" requirements with entity specific requirements.

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: The SDT thanks you for your comment. Your assumption is correct. The SDT proposes and discusses in the Implementation Plan the retirement of PRC-018-1 (except for Maintenance and Testing requirements) and the merger of those requirements with a revision of PRC-002-1, resulting in a new standard, PRC-002-2.		
SPP System Protection and Control Working Group	Yes	Please clarify the term "entity specific requirements" in Question #1.
Response: The SDT thanks you for your comment. Entity specific requirements are requirements in a standard that apply to entities that are the relevant functional entities as described in the Functional Model. In the case of the proposed standard, the relevant functional entities to which the standard requirements apply are the Planning Coordinator, the Transmission Owners and the Generator Owners.		
Members of the WECC Disturbance Monitoring Work Group	Yes	

Organization	Yes or No	Question 1 Comment
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 to an overall NERC defined methodology. In the absence of a NERC defined methodology, a SAR should be introduced to produce one.
Response: The SDT thanks you for your comment. The drafting team has made revisions and has related location determination to the results of short circuit study for the area of the system relevant to the functional entity. New proposed criteria for Sequence of Events (SOE) and Fault Recorder (FR) data requires that monitoring be installed on 20% of the bus locations with the highest calculated three-phase short circuit MVA within the Planning Coordinator's fault study area at 1500 MVA or above, as calculated under normal configurations and connected at a 100 kV or higher voltage. In addition there is are new proposed criteria for Dynamic Data Recorder (DDR) data that requires monitoring be installed on 5% of bus locations within a Planning Coordinator's area that includes bus locations with the highest calculated three-phase short circuit MVA at 1500 MVA or above, connected at 100kV or higher and includes generators with a nameplate rating of 1000 MVA or above, or for an aggregate nameplate rating of 1000 MVA or above with a common point of interconnection as identified by the Planning Coordinator's study.		
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: The SDT thanks you for your comment. Based on industry comments, the SDT revised the DDR requirement in the latest revision of proposed R17 to reflect current practice for determining DDR location requirements by assigning responsibility to the Planning Coordinators. Planning Coordinators are required to establish a list of DDR monitored locations every five years that includes 5% or the bus locations within the Planning Coordinator's area. The new proposed criteria for DDR requires monitoring be installed on 5% of bus locations within a Planning Coordinator's area that includes bus locations with the highest calculated three-phase short circuit MVA at 1500 MVA or above, connected at 100kV or higher and includes generators with a nameplate rating of 1000 MVA or above, or for an aggregate nameplate rating of 1000 MVA or above with a common point of interconnection as identified by the Planning Coordinator's study. Requirement R23 requires that the Transmission Owners and Generator Owners record DDR data at the locations specified by the Planning Coordinators.		
PacifiCorp	Yes	
Bonneville Power	Yes	Is there a purpose to the analyses proposed. How much detail is really needed?

Organization	Yes or No	Question 1 Comment
Administration		
Response: The SDT thanks you for your comment. The purpose of the standard is "To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES)"; therefore, the standard only establishes requirements for data collection and does not define how the data will be used or the extent of the analysis.		
FirstEnergy	Yes	We agree that it will be beneficial to consolidate these standards into one document.
Response: The SDT thanks you for your comment.		
Florida Power & Light	Yes	A single standard to define the installation application of DMEs makes good sense.
Response: The SDT thanks you for your comment.		
US Bureau of Reclamation	Yes	It is good idea to make a single document to cover all DME requirements
Response: The SDT thanks you for your comment.		
Cowlitz County PUD	Yes	A single standard addressing disturbance monitoring is GREATLY appreciated. This will simplify compliance efforts.
Response: The SDT thanks you for your comment.		
City of Tallahassee (TAL)	Yes	Any time we can combine similar requirements into the same standard we are better off.
Response: The SDT thanks you for your comment.		
PHI (PEPCO Holdings Inc.)	Yes	No need for different standards to cover DM.

Organization	Yes or No	Question 1 Comment
Response: The SDT thanks you for your comment.		
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: The SDT thanks you for your comment. The purpose of the standard is "To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES)"; therefore, the standard states requirements only for data collection and does not define how the data will be used or the extent of the analysis. The SDT believes that the granularity of data specifications may vary greatly depending upon the analysis tools selected and by vendors of monitoring equipment. The SDT has addressed what must be done, and does not specify how it is to be done.		
Hydro-Québec TransEnergie	Yes	We assumed that the question refers to the merging of Standards PRC-002-1 and PRC-018-1.
Response: The SDT thanks you for your comment. Your assumption is correct. The SDT proposes and discusses in the Implementation Plan the retirement of PRC-018-1 (except for Maintenance and Testing requirements) and the merger of those requirements with a revision of PRC-002-1, resulting in a new standard, PRC-002-2.		
WECC	Yes	I also agree with changing the fill in the blank characteristics into entity specific requirements
Response: The SDT thanks you for your comment.		
Progress Energy Florida	Yes	
Los Angeles Department of Water & Power	Yes	

Organization	Yes or No	Question 1 Comment
NYISO	Yes	
Puget Sound Energy	Yes	
PG&E System Protection	Yes	
Dominion	Yes	
MRO NERC Standards Review Subcommittee	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Tri-State Generation and Transmission Association	Yes	
NERC	Yes	
Schneider Electric	Yes	
Grant County PUD	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
IRC Standards Review Committee	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 1 Comment
National Grid	Yes	
Manitoba Hydro	Yes	
Wisconsin Electric	Yes	
Exelon Generation LLC	Yes	
ITC Transmission, METC	Yes	
DTE Energy/Detroit Edison	Yes	
NV Energy	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
E.ON U.S.	Yes	
Progress Energy Carolina, Inc.	Yes	

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

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: Commenters generally agreed that the mapping document demonstrated that all the appropriate requirements of PRC-002-1 and PRC-018-1 (except maintenance and testing) have been reflected in the proposed PRC-002-2.

Note that PRC-002-1 had an effective date of nine months after BOT adoption (BOT adoption was 8/2/06). This means that RRO requirements were to be in place by 5/2/07. At that time, however, the standards process was transitioning to the current FERC approval and enforcement rules and procedures. Because of the transition, the RROs may or may not have completed the development of the appropriate requirements since PRC-002-1, a fill-in-the-blank standard, was not considered enforceable. To ensure that the SDT does not create a standard that may appear to be retroactive and inadvertently create a non-compliant situation, the SDT has advanced the date to be reasonable with any installations needing revision.

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: The SDT thanks you for your comment. PRC-002-1 had an effective date of nine months after BOT adoption (BOT adoption was 8/2/06). This means that RRO requirements were to be in place by 5/2/07. At that time, however, the standards process was transitioning to the current FERC approval and enforcement rules and procedures. Because of the transition, the RROs may or may not have completed the development of the appropriate requirements since PRC-002-1, a fill-in-the-blank standard, was not considered enforceable. To ensure that the SDT does not create a standard that may appear to be retroactive and inadvertently create a non-compliant situation, the SDT will advance the dates to be reasonable with any installations needing revision. Data file naming is not the subject of “what” is required but a matter of “how” processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated is at the discretion of the users.		
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

Organization	Yes or No	Question 2 Comment
		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: Please see the response provided for this same comment repeated in question #3.		
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: The applicability section 4.2 states that PRC-002-2 applies to generator owners. The SDT realized generator nameplate rating for a single unit 500 MVA or higher is a requirement and should be placed in the requirement section of the standard. Requirements specific to generator MVA are stated in the revised draft standard.		
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: The purpose of this standard is to ensure that disturbance data is available. The conditions under which the data is used, why it is used, and by which entity it is used are as diverse of the range of disturbances and system configurations. Since neither this standard, nor its predecessors, established "what" analyses are required and by which entity they were required, it was not possible to establish reporting "requirements" which are really a matter of "how" the available information can be communicated. Compliance can use information communicated to a requesting entity to verify that the required data was actually available. The SDT believes that the information being "moved" to the compliance section is not requirements, but is part of compliance elements that relate to the requirements.		
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.
Response: PRC-002-1 had an effective date of nine months after BOT adoption (BOT adoption was 8/2/06). This means that RRO requirements were to be in place by 5/2/07. At that time, however, the standards process was transitioning to the current FERC approval and enforcement rules and procedures. Because of the transition, the RROs may or may not have completed the development of the appropriate requirements since PRC-002-1, a fill-in-the-blank standard, was not considered enforceable. To ensure that the SDT does not create a standard that may appear to be retroactive and inadvertently create a non-compliant		

Organization	Yes or No	Question 2 Comment
situation, the SDT will advance the dates to be reasonable with any installations needing revision. Data file naming is not the subject of "what" is required but a matter of "how" processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated is at the discretion of the users.		
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: PRC-002-1 had an effective date of nine months after BOT adoption (BOT adoption was 8/2/06). This means that RRO requirements were to be in place by 5/2/07. At that time, however, the standards process was transitioning to the current FERC approval and enforcement rules and procedures. Because of the transition, the RROs may or may not have completed the development of the appropriate requirements since PRC-002-1, a fill-in-the-blank standard, was not considered enforceable. To ensure that the SDT does not create a standard that may appear to be retroactive and inadvertently create a non-compliant situation, the SDT will advance the dates to be reasonable with any installations needing revision. Data file naming is not the subject of "what" is required but a matter of "how" processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated is at the discretion of the users.		
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: The SDT thanks you for your comments. Only those GOs and TOs that are identified on the list of locations for which SOE, FR, or DDR functionality must be provided will be required to provide the information. The SDT believes that will be approximately 20% of the locations for SOE and FR, and 5% for DDR. The +/- 2 millisecond requirement is not a new requirement (it was in FERC approved PRC-018-1, Requirement R1.1). The proposed implementation schedule is consistent with PRC-018-1 and with PRC-002-1.		
Southern Company - Transmission	Yes	No further comment.

Organization	Yes or No	Question 2 Comment
Response: The SDT thanks you for your comment.		
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: The SDT thanks you for your comment. Protection schemes are not addressed in this standard. The standard is intended to outline the requirements for DME; it is up to the individual entity to ensure that DME will not interfere with the functionality of their protection schemes.		
JEA	Yes	Good job on mappring all the requirements!!
Response: The SDT thanks you for your comment.		
US Bureau of Reclamation	Yes	
Los Angeles Department of Water & Power	Yes	
Dominion	Yes	
American Electric Power	Yes	
Florida Power & Light	Yes	
Bonneville Power Administration	Yes	
Manitoba Hydro	Yes	
Progress Energy Carolina, Inc.	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	

Organization	Yes or No	Question 2 Comment
Cowlitz County PUD	Yes	
Progress Energy Florida	Yes	
Puget Sound Energy	Yes	
Tri-State Generation and Transmission Association	Yes	
DTE Energy/Detroit Edison	Yes	
NYISO	Yes	
NERC	Yes	
Schneider Electric	Yes	
NV Energy	Yes	
PG&E System Protection	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
Entergy Services, Inc	Yes	
Independent Electricity System Operator	Yes	
ITC Transmission, METC	Yes	
Exelon Generation LLC	Yes	

Organization	Yes or No	Question 2 Comment
San Diego Gas and Electric Co.	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
New York Independent System Operator	Yes	
IRC Standards Review Committee	Yes	
SPP System Protection and Control Working Group	Yes	
Beckwith Electric Co	Yes	
Duke Energy	Yes	
Xcel Energy	Yes	
Kansas City Power & Light	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Wisconsin Electric	Yes	

Organization	Yes or No	Question 2 Comment
PNM	Yes	
Portland General Electric		
Salt River Project		
British Columbia Transmission Corporation		
Pacific Northwest National Laboratory		
PacifiCorp		
Grant County PUD		
CenterPoint Energy		
National Grid		
Arizona Public Service Co.		
Utility System Efficiencies, Inc.		
WECC		
Members of the WECC Disturbance Monitoring Work Group		
TransAlta		

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: Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2, Requirement R27. Eventually, a new SAR will be proposed and the requirements related to disturbance monitoring equipment will be fully developed and assigned to another standard.

Organization	Yes or No	Question 3 Comment
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.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
SERC Protection and Controls Sub-committee	No	Prefer that M&T continue to be contained within this standard.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
Dominion	No	Prefer M&T to be contained within this standard. Do not move DME M&T to a totally new standard.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		

Organization	Yes or No	Question 3 Comment
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
ITC Transmission, METC	No	The FERC-approved PRC-018-1 requires a maintenance and testing program for DME and it should be

Organization	Yes or No	Question 3 Comment
		included in the new PRC-002-2.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT		

Organization	Yes or No	Question 3 Comment
proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
IRC Standards Review Committee	Yes	The SRC agrees with the proposal to exclude maintenance and testing from this standard.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
MRO NERC Standards Review Subcommittee	Yes	Having a separate maintenance and testing standard may be easier to administrate for most utilities.
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
NERC	Yes	They should be included in PRC-005 -- Transmission Protection System Maintenance and Testing
Response: The SDT thanks you for your comment and for your suggestion. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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 for PRC-002-2 work on the M&T standard.
Response: The SDT thanks you for your comment. The SDT agrees with your description of the appropriate separation of concepts. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment		

Organization	Yes or No	Question 3 Comment
belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
City of Tallahassee (TAL)	Yes	It would be ideal if ALL Maintenance and Testing requirements were in one standard!
Response: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: Data file formatting is not the subject of “what” is required by the standard but a matter of “how” processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated is at the discretion of the users.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment		

Organization	Yes or No	Question 3 Comment
belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
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: The SDT thanks you for your comment. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2		
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: The SDT thanks you for your comment. The SDT does not, in its proposal, intend a "mix" of disturbance monitoring requirements with system protection requirements; rather, the SDT intends for the specific requirements for each type of function to be covered. Commenters generally agreed that maintenance and testing of disturbance monitoring equipment belongs in another standard. Since such requirements are currently in FERC approved PRC-018-1, which the SDT is proposing for retirement, the SDT proposes temporarily addressing these requirements in PRC-002-2.		
Bonneville Power Administration	Yes	
Los Angeles Department of Water & Power	Yes	
Grant County PUD	Yes	
Tri-State Generation and Transmission Association	Yes	
Portland General Electric	Yes	
Independent Electricity System Operator	Yes	
PacifiCorp	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
Schneider Electric	Yes	

Organization	Yes or No	Question 3 Comment
Puget Sound Energy	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
New York Independent System Operator	Yes	
NYISO	Yes	
San Diego Gas and Electric Co.	Yes	
PG&E System Protection	Yes	
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
Northeast Utilities	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy	Yes	
Entergy Services, Inc	Yes	
Arizona Public Service Co.	Yes	
Duke Energy	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	

Organization	Yes or No	Question 3 Comment
CenterPoint Energy	Yes	
Salt River Project	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
British Columbia Transmission Corporation	Yes	
Tucson Electric Power	Yes	
Wisconsin Electric	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
PNM	Yes	
TransAlta		
National Grid		

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: Comments indicated that those who responded agreed with the intent of the standard. However, stakeholders pointed out that the wording of the requirements and tables required clarification. Additionally, commenters stated that the location criteria for DME seemed arbitrary, and asked what the drafting team's technical justification was for the location criteria. Some commenters stated that the use of the term "substation" presented in the requirements was misunderstood.

The drafting team undertook a significant rewriting of the draft standard. The requirements were made clearer and the tables were eliminated. To determine location criteria, a task team was formed to develop a technical basis for the requirements. Based on data received, the task team developed location criteria for SOE and FR data to be 20% of bus locations with the highest calculated short circuit MVA level. To address the misunderstanding of the use of the term "substation," the drafting team dropped the use of the term and focused on buses as a location criterion.

Organization	Yes or No	Question 4 Comment
PNM	No	The defining sum of lines and transformers should be 4 instead of 3. The sum of 3 will exclude few sites.
Response: The SDT thanks you for your comment. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established new criteria for the location of DME that includes a short circuit MVA criteria. This is included in the revised draft standard.		
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: The SDT thanks you for your comment. The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this.		

Organization	Yes or No	Question 4 Comment
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: The SDT thanks you for your comment. The drafting team recognizes that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification. The revised standard should ensure that sufficient elements are monitored. The team agrees that if no DME is installed at a terminal, but all remote terminals have DME that monitor the required elements, then no DME should be required at that particular terminal.		
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: The SDT thanks you for your comment. The standard provides criteria for what elements to monitor. It does not specify the type or number of DME to be installed. How the elements are monitored is up to the TOs and GOs.		
Entergy Services, Inc	No	a) 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. b) Also, the wording of R1.1 may does not seem be clear to everyone. Suggest the use of diagrams for clarity.
Response: The SDT thanks you for your comment. a) To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes a short circuit MVA criteria. This is included in the revised draft standard. b) The drafting team recognizes that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the		

Organization	Yes or No	Question 4 Comment
requirements have been rewritten to provide clarification. The drafting team understands your comment regarding the use of diagrams to further clarify the standard. However, the drafting team does not believe that these diagrams belong in the standard, but rather in an FAQ or other technical document. The drafting team will consider writing an FAQ in addition to the standard.		
Brazos Electric Power Cooperative, Inc.	No	The approach needs better engineering support of the criteria.
Response: The SDT thanks you for your comment. The drafting team agrees that a technical basis for the criteria is needed. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. It is included in the revised draft standard.		
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: The SDT thanks you for your comment. The drafting team understands your comment, however, in order to avoid a fill-in-the-blank standard, a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, which was rejected by FERC. This standard will establish a baseline set of criteria and does not restrict the regions from having input into the location of DME.		
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: The SDT thanks you for your comment. The drafting team recognizes that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
American Electric Power	No	AEP believes that there is some misunderstandings of the term "Substation" as applied in the standard. The

Organization	Yes or No	Question 4 Comment
		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: The SDT thanks you for your comment. Based on industry, feedback the SDT will not be using “substation” to define the locations. Instead, the standard uses the bus as a requirement in the location criteria.		
TransAlta	No	a)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.b)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. c) 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: The SDT thanks you for your comment. a) The purpose of the standard is to establish the criteria for the monitoring of system elements for disturbance analysis. The requirements in the draft standard do offer guidance in selection of locations for DME. The drafting team understands that the requirements may represent a significant burden on resources; however, the purpose of the standard is to ensure that sufficient elements are monitored to facilitate the analysis of power system disturbances. b) Based on other comments received, the drafting team understands that certain elements may be excluded and there may be some adjacent locations that could have duplicate data. The drafting team also reviewed EOP-004-1 criteria and determined that it does not provide criteria for the selection of locations based on measureable criteria. c) Disturbance data includes sequence-of-events and fault data, along with dynamic disturbance data. Typically, an RC uses the dynamic disturbance data to analyze a disturbance, and a utility will use SOE and FR data. The original PRC-002 requires that the regional reliability organizations develop criteria for the		

Organization	Yes or No	Question 4 Comment
location of DME, which was rejected by FERC. However, in order to avoid a fill-in-the-blank standard, a defined set of criteria is required. The standard establishes this set of criteria, and it does not restrict the regions from having input into the location of DME.		
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: The SDT thanks you for your comment. The draft standard is focused on recording requirements and elements to be monitored, not the type of equipment or how each element is monitored. It is the responsibility of the TO and GO to decide what equipment to use and how they will meet the requirement.		
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: The SDT thanks you for your comment. The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this.		
SERC Protection and Controls Sub-committee	No	Agree with the approach given our understanding of thestandard's intent. a) The documents wording and Tables need to be clearerand more consistent. b) 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. c) 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. d) We suggest that you make use of diagrams to make the intent clearer.
Response: The SDT thanks you for your comment. a) The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the		

Organization	Yes or No	Question 4 Comment
requirements have been rewritten to provide clarification. b) The drafting team agrees with your suggestion on excluding radial lines and has changed the wording of the requirements in the revised draft standard toaccount for this. c) The purpose of the standard is "To ensure that Facility owners, whether they are a TO or GO, monitor BES elements to ensure the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES)." Based on comments received, the drafting team recognized that the tables contained in the draft standard were confusing and unclear. The tables have been eliminated from the revised draft standard. d) The drafting team understands your comment regarding the use of diagrams to further clarify the standard. However, the drafting team does not believe that these diagrams belong in the standard, but rather in an FAQ or other technical document. The drafting team will consider writing an FAQ in addition to the standard.		
PacifiCorp	No	a) 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: The SDT thanks you for your comment. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this		
Southern Company - Transmission	No	a) 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. b) We are particularly keen on the idea of using diagrams to further clarify and illustrate the intent of the standard where needed. c) 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: The SDT thanks you for your comment. a) The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification. b) The drafting team understands your comment regarding the use of diagrams to further clarify the standard. However, the drafting team does not believe that		

Organization	Yes or No	Question 4 Comment
these diagrams belong in the standard, but rather in an FAQ or other technical document. The drafting team will consider writing an FAQ in addition to the standard. c) The drafting team understands your concern related to the location of disturbance monitoring equipment installed for the purpose of recording disturbance data,, and others share this concern. In order to develop a continent-wide standard, it is necessary to develop a set of measurable criteria.. The team's opinion is that if location of DME is done by stability study alone, it will not be measurable. The team elected to use a three-phase short circuit MVA criteria based on data voluntarily provided by utilities in different regions to determine monitoring requirements. The revised draft of the standard is based on this set of criteria.		
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: The SDT thanks you for your comment. The SDT agrees that this standard is based on physical aggregation, not electronic aggregation. The criteria specify the number of elements at a location and are not market-based.		
Dominion	Yes	We agree with the approach given our understanding of the standard's intent. a) 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 b) 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. c) We suggest exempting radial lines without transmission connected generation. Do 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: The SDT thanks you for your comment. a) The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification. b) The drafting team agrees with your comment regarding clarification of the generator output breaker. In the revised standard, it has added wording to clarify what the generator output breaker is, along with a statement confirming that it can be a low or high side breaker. c) The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this.		

Organization	Yes or No	Question 4 Comment
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: The SDT thanks you for your comment. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: The SDT thanks you for your comment. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established a revised set of criteria for the location of DME that includes a short circuit MVA criteria. This is included in the revised draft standard.		
PG&E System Protection	Yes	The Threshold for the number of elements is too low.
Response: The SDT thanks you for your comment. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: The SDT thanks you for your comment. The drafting team recognized that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
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

Organization	Yes or No	Question 4 Comment
		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: The SDT thanks you for your comment. The drafting team recognizes that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
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: The SDT thanks you for your comment. To address concerns regarding location criteria and the number of elements, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your positive comments.		
City of Tallahassee (TAL)	Yes	I agree with the approach. This approach makes it clear where it is needed, except as noted below.
Response: Thank you for your positive comments.		
Progress Energy Carolina, Inc.	Yes	These requirements will create consistancy in the required locations where the regions "opinions" are not different.
Response: Thank you for your positive comments.		
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: Thank you for your comments.		
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: The SDT thanks you for your comment. The purpose of the standard is “To ensure that Facility owners collect the data needed to facilitate analyses of Disturbances on the Bulk Electric System (BES).” Therefore, the standard only establishes requirements for data collection and does not define how the data will be used or the extent of the analysis. The opinion of the drafting team is that if dual ownership exists, the two companies may work out an agreement to address the requirements.		
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: The SDT thanks you for your comment. The drafting team understands your comment; however, in order to avoid a fill-in-the-blank standard, a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, which was rejected by FERC. The standard will establish a baseline set of criteria and does not restrict the regions from having input into the location of DME.		
Members of the WECC Disturbance Monitoring Work Group	Yes	
SPP System Protection and Control Working Group	Yes	
FirstEnergy	Yes	
MRO NERC Standards Review	Yes	

Organization	Yes or No	Question 4 Comment
Subcommittee		
Portland General Electric	Yes	
Manitoba Hydro	Yes	
NV Energy	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
NYISO	Yes	
Exelon Generation LLC	Yes	
Independent Electricity System Operator	Yes	
British Columbia Transmission Corporation	Yes	
Northeast Power Coordinating Council	Yes	
Arizona Public Service Co.	Yes	
Xcel Energy	Yes	
ITC Transmission, METC	Yes	

Organization	Yes or No	Question 4 Comment
Wisconsin Electric	Yes	
Schneider Electric	Yes	
New York Independent System Operator	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Progress Energy Florida	Yes	
San Diego Gas and Electric Co.	Yes	
Beckwith Electric Co	Yes	
Salt River Project	Yes	
Alberta Electric System Operator	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Kansas City Power & Light	Yes	
Northeast Utilities		a) 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. b) 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

Organization	Yes or No	Question 4 Comment
		be out of service.
Response: The SDT thanks you for your comment. a) To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established a revised set of criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. b) The team agrees with your comment; however, the team believes the revised standard will provide coverage for some buses at 100kV and above that could have a significant impact during events.		
Puget Sound Energy		
DTE Energy/Detroit Edison		
WECC		

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: Many stakeholders questioned the generator nameplate criteria. Some thought 500MVA and 1500MVA were too high, and some thought them too low. Commenters stated that the GO and TO responsibilities were not clear. In addition, as in question 4, commenters questioned the technical basis for the number of elements for SOE and FR.

The drafting team formed a task-team to develop a technical justification for location criteria for SOE, FR, and DDR functionality. This task team developed a set of criteria based on short circuit MVA and generator nameplate rating based on data supplied by several utilities. The draft standard was rewritten to incorporate the criteria as part of the requirements. In rewriting the standard, the drafting team eliminated the tables and modified the wording of the requirements. The new draft requirements clarify TO and GO responsibility.

Organization	Yes or No	Question 5.1 Comment
Northeast Power Coordinating Council	No	a) 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. b) Monitoring should not be limited to breaker positions--this will improve event analysis. c) We do not feel that the 200kV threshold is an appropriate criteria for assessing criticality.
Response: Thank you for your comments. a) The drafting team agrees that smaller generators could have a significant impact on the power system; however, the standard establishes baseline criteria to ensure data is available. The standard does not prevent a region from having or developing more stringent criteria. b) The drafting team discussed not limiting SOE to the breaker position and decided that the breaker position is sufficient SOE data for determining what		

Organization	Yes or No	Question 5.1 Comment
occurred during a wide area event. c) To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. The drafting team agrees that smaller generators could have a significant impact on the power system; however, the standard establishes baseline criteria to ensure data is available. The standard does not prevent a region from having or developing more stringent criteria.		
NERC	No	Disagree with 200 kv and above...should be 100 kv and above.
Response: Thank you for your comments. The drafting team has changed the threshold to 100kV.		
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
Response: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. The drafting team agrees that smaller generators could have a significant impact on the power system; however, the standard establishes baseline criteria to ensure data is available. The standard does not prevent a region from having or developing more stringent criteria.		
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: Thank you for your comments. The drafting team does not agree with the recommendation. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft		

Organization	Yes or No	Question 5.1 Comment
standard.		
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: Thank you for your comments. The standard defines the elements that need to be monitored and identifies that the SOE shall be recorded. The GO is responsible for ensuring that the breaker SOE is captured but can accomplish this through agreement with the TO that is monitoring the breaker.		
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: Thank you for your comments. The drafting team does not agree with the recommendation. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. The drafting team does not agree with the recommendation. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Hydro-Québec TransEnergie (HQT)	No	a) 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. b) 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.

Organization	Yes or No	Question 5.1 Comment
Response: Thank you for your comments. a) The drafting team understands your comment; however, in order to avoid a fill-in-the-blank standard a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, which was rejected by FERC. The standard will establish baseline criteria and does not restrict the regions from having input into the location of DME. b) The drafting team understands that there are facilities at 200kV that are not critical and there are critical facilities at 100kV. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. The drafting team discussed not limiting SOE to the breaker position and decided that the breaker position is sufficient SOE data for determining what occurred during a wide area event.		
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: Thank you for your comments. The drafting agrees that smaller generators could have a significant impact on the power system; however, the standard establishes baseline criteria to ensure data is available. The standard does not prevent a region from having or developing more stringent criteria.		
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: Thank you for your comments. The drafting team does not agree with the recommendation. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Beckwith Electric Co	No	a) Recommend changing it to: "The status of GSU circuit breakers and sequence of events data of protective relay 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. b) This requirement should be based on

Organization	Yes or No	Question 5.1 Comment
		the plant size and not the connected transmission voltage.
Response: Thank you for your comments. a) The drafting team discussed not limiting SOE to the breaker position and decided that the breaker position is sufficient SOE data for determining what occurred during a wide area event. b) The drafting team believes that the standard criteria for generation is based on plant size where connected to transmission systems at 200kV and above. The standard does not prevent a region from developing more stringent criteria.		
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: Thank you for your comments. The SDT agrees that this standard is based on physical aggregation, not electronic aggregation. The criteria specify the number of elements at a location and are not market-based.		
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.
Response: Thank you for your comments. The focus of the standard is monitoring of the bulk electric system. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Members of the WECC Disturbance Monitoring Work Group	Yes	We agree with the nameplate values. However, we have two questions. a) 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 b) 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: Thank you for your comments. a) The GO would be responsible for working with the TO or other GO owner to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		

Organization	Yes or No	Question 5.1 Comment
SERC Engineering Committee Planning Standards Subcommittee	Yes	These values seem to be in the appropriate range.
Response: Thank you for your positive comment.		
Bonneville Power Administration	Yes	For generating stations with split interconnection voltages (some units connected below 200 kV), define how to interpret.
Response: Thank you for your comments. The standard applies to generation connected to the Bulk Electric System.		
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: Thank you for your comments. The drafting team agrees that a technical basis for the criteria is needed. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Los Angeles Department of Water & Power	Yes	These values appear reasonable and affect several of our generating stations.
Response: Thank you for the positive comment.		
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: Thank you for your comments. The drafting team agrees that a technical basis for the criteria is needed. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
PG&E System Protection	Yes	We agree with the nameplate values. However, we have two questions. a) R2 and table 2.1. requires the GO to

Organization	Yes or No	Question 5.1 Comment
		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 b) 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: Thank you for your comments. a) The GO would be responsible for working with the TO or other GO owner to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
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: Thank you for your comments.		
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. a) 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? b) 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: Thank you for your comments. a) The GO would be responsible for working with the TO or other GO owner to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
Puget Sound Energy	Yes	We agree with the nameplate values. However, we have two questions. a) 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? b) 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: Thank you for your comments.		

Organization	Yes or No	Question 5.1 Comment
a) The GO would be responsible for working with the TO or other GO owner to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
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: Thank you for your comments. The standard has been reworded significantly since the prior posting.		
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: Thank you for your comments. If each plant has a single generator at 500 MVA or above, then each is required to be monitored. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
NV Energy (fka Sierra Pacific Resources)	Yes	These MVA and voltage levels appear to be appropriate for the intent of this Standard.
Response: Thank you for the positive comment.		
Arizona Public Service Co.	Yes	a) 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. b) 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

Organization	Yes or No	Question 5.1 Comment
		portions not connected to the 200 kV and above system should not be required to meet the standard.
Response: Thank you for your comments. a) The standard defines the elements that need to be monitored and identifies that the SOE shall be recorded. The GO is responsible for ensuring that the breaker SOE is captured, but can accomplish this through agreement with the TO that is monitoring the breaker. b) The standard applies to generation connected to the BES.		
Tucson Electric Power	Yes	We agree with the nameplate values. However, we have two questions. a) 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? b) 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: Thank you for your comments. a) The GO would be responsible for working with the TO or other GO to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
Utility System Efficiencies, Inc.	Yes	I agree with the nameplate values. However, I have two questions. a) 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? b) 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: Thank you for your comments. a) The GO would be responsible for working with the TOor other GO to ensure that the required elements are monitored. b) The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
Southern Company - Transmission	Yes	No further comment.
Dominion	Yes	
Entergy Services, Inc	Yes	

Organization	Yes or No	Question 5.1 Comment
PacifiCorp	Yes	
San Diego Gas and Electric Co.	Yes	
Independent Electricity System Operator	Yes	
Tri-State Generation and Transmission Association	Yes	
Grant County PUD	Yes	
Duke Energy	Yes	
Alberta Electric System Operator	Yes	
NV Energy	Yes	
ITC Transmission, METC	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Progress Energy Carolina, Inc.	Yes	
Xcel Energy	Yes	
JEA	Yes	
Florida Power & Light	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 5.1 Comment
Progress Energy Florida	Yes	
Salt River Project	Yes	
SERC Protection and Controls Sub-committee	Yes	
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	
National Grid		
Brazos Electric Power Cooperative, Inc.		
Pacific Northwest National Laboratory		
WECC		
Schneider Electric		
CenterPoint Energy		

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: Commenters questioned the applicability of the standard to generators and the generator nameplate ratings in the criteria. They also questioned the technical justification for the criteria and recommended that bus voltage be monitored.

The standard does apply to generators connected to the BES system. The drafting team believes that monitoring the contributions from generators during a fault or wide area event will aid in the analysis of these events. The drafting team formed a task-team to develop a technical justification for location criteria for SOE, FR, and DDR functionality. This task team developed criteria based on short circuit MVA and generator nameplate rating based on data that was supplied by several utilities. The draft standard has been rewritten to incorporate the criteria as part of the requirements. The drafting team agrees that bus voltage should be monitored where applicable.

Organization	Yes or No	Question 5.2 Comment
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: Thank you for your comments. Due to a lack of consensus from industry on generator size requirements for monitoring, the drafting team performed a study using data collected for the MVA study to determine what we think are appropriate generator nameplate ratings for monitoring. The data showed that appropriate criteria: 1- for SOE is the individual generators with a nameplate rating of 20 MVA or above or for an aggregate nameplate rating of 75 MVA or above connected to the facilities for FR is generators with a nameplate rating of 500 MVA or above, or for an aggregate nameplate rating of 500 MVA or above with a common point of electrical interconnection connected to the facilities contains DDR criteria for Generator Owners but does not include an MVA threshold.		
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: Thank you for your comments. The drafting team does not agree that bus voltage is always required to perform a forensic analysis. For a breaker-and-a- half where each line has individual CCVTs for protection, bus CCVTs are typically not installed. For events, voltages from the lines can be used for any forensic analysis.		

Organization	Yes or No	Question 5.2 Comment
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
Response: Thank you for your comments. The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
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: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This included in the revised draft standard.		
DTE Energy/Detroit Edison	No	Please see comment for 5.1.
Response: Thank you for your comments. Please refer to our response for 5.1.		
Hydro-Québec TransEnergie (HQT)	No	See Q5.1 answer above.
Response: Thank you for your comments. Please refer to our response for 5.1.		
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: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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

Organization	Yes or No	Question 5.2 Comment
		200 kV and above system should not be required to meet the standard.
Response: Thank you for your comments. A requirement that applies to only new plants and grandfathers existing plants is not practical. Such a requirement could result in insufficient data for analysis during a wide-area event. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard The standard defines the elements that need to be monitored and identifies that the SOE shall be recorded. The GO is responsible for ensuring that the breaker SOE is captured, but can accomplish this through agreement with the TO that monitors the breaker. The standard applies to generation connected to the BES.		
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: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard The drafting team believes that the standard criteria for generation is based on plant size where connected to transmission systems at 200kV and above		
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: Thank you for your comments. The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
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: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
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."

Organization	Yes or No	Question 5.2 Comment
Response: Thank you for your comments. The SDT agrees that this standard is based on physical aggregation, not electronic aggregation. The criteria specify the number of elements at a location and are not market-based.		
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: Thank you for your comments. The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES..		
Southern Company - Transmission	Yes	No further comment.
Response: Thank you for your comments.		
SERC Engineering Committee Planning Standards Subcommittee	Yes	These values seem to be in the appropriate range.
Response: Thank you for your positive comments.		
Bonneville Power Administration	Yes	For generating stations with split interconnection voltages (some units connected below 200 kV), define how to interpret.
Response: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES. The standard applies to generation connected to the Bulk Electric System.		
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: Thank you for your comments. To address concerns regarding location criteria and the number of elements specified, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the		

Organization	Yes or No	Question 5.2 Comment
location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Los Angeles Department of Water & Power	Yes	These values appear reasonable and affect several of our generating stations.
Response: Thank you for your positive comments.		
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: Thank you for your comments. The requirement is based on the typical connections found at TO facilities and GO facilities.		
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 greater than 200 kV? Is this standard applicable to this plant?
Response: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES..		
Cowlitz County PUD	Yes	Again, I feel the burden of proof should be on those who would argue for more stringent criteria.
Response: Thank you for your comments.		
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?
Response: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES.		
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: Thank you for your comments. . The first test would be to determine if a single generator meets the criteria; if not, the standard applies to generation connected to the BES..		

Organization	Yes or No	Question 5.2 Comment
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: Thank you for your comments.		
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: Thank you for your comments. The format of the standard has been changed significantly since the prior posting.		
NV Energy (fka Sierra Pacific Resources)	Yes	These MVA and voltage levels appear to be appropriate for the intent of this Standard.
Response: Thank you for your positive comments.		
Florida Power & Light	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Tri-State Generation and Transmission Association	Yes	
Salt River Project	Yes	
Progress Energy Florida	Yes	
ITC Transmission, METC	Yes	

Organization	Yes or No	Question 5.2 Comment
NYISO	Yes	
Dominion	Yes	
SERC Protection and Controls Sub-committee	Yes	
Manitoba Hydro	Yes	
Progress Energy Carolina, Inc.	Yes	
PacifiCorp	Yes	
Wisconsin Electric	Yes	
Entergy Services, Inc	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
JEA	Yes	
Alberta Electric System Operator	Yes	

Organization	Yes or No	Question 5.2 Comment
Duke Energy	Yes	
SPP System Protection and Control Working Group	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Northeast Power Coordinating Council	Yes	
British Columbia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
PNM	Yes	
Grant County PUD		
National Grid		
Brazos Electric Power Cooperative, Inc.		
WECC		
Pacific Northwest National Laboratory		
Schneider Electric		

Organization	Yes or No	Question 5.2 Comment
CenterPoint Energy		

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: Comments stated that the substations with seven lines as a location criterion for DDR functionality was arbitrary and commenters asked about the technical justification for the criteria. Some suggested that DDRs be located by study rather than by the number of lines. Commenters stated that in general, fewer DDRs are required than FRs. In addition, commenters stated that radial lines should be excluded from the criteria.

The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations. The number of circuits and the word substation was removed from the requirement.

Organization	Yes or No	Question 5.3 Comment
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: Thank you for your comments. The drafting team acknowledges your concern, but in order to avoid a fill-in-the-blank standard, a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, and that was rejected by FERC. The standard will establish baseline criteria and does not restrict the regions from having input into the location of DME. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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

Organization	Yes or No	Question 5.3 Comment
Response: Thank you for your comments. The drafting team acknowledges your concern, but in order to avoid a fill-in-the-blank standard, a set of criteria is required. The original PRC-002 requires that the regional reliability organizations develop criteria for the location of DME, and that was rejected by FERC. The standard will establish baseline criteria and does not restrict the regions from having input into the location of DME. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The drafting team agrees with your suggestion on excluding radial lines and has modified the requirements in the revised draft standard to address this. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your recommendation. The drafting team realizes the wording in the standard is not clear and has changed it for clarity.		
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification
Response: Thank you for your comments. Please see our response to your Q4 comment.		

Organization	Yes or No	Question 5.3 Comment
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: Thank you for your comments. The drafting team realizes the wording in the standard is not clear and has changed it for clarity.		
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: Thank you for the recommendation. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Hydro-Québec TransEnergie (HQT)	No	See Q5.1 answer above.
Response: Thank you for your comments. Please refer to the response in Q5.1 above.		
Entergy Services, Inc	No	The number of lines criteria is too arbitrary and will require an excessive number of installations at some entities and

Organization	Yes or No	Question 5.3 Comment
		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: Thank you for your comments. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The standard drafting team recognizes that it may be difficult to implement the criteria for the reasons stated. However, the drafting team believes the original criteria established are a good baseline to ensure that data is available for disturbance analysis.		
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: Thank you for your comments. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The drafting team disagrees with your recommendation to install DDR only at substations that have direct interconnections to generating units. DDR is typically installed at the points of a transmission system where a disconnect of load or generation would have a significant impact on system stability. This location may be far removed from where generation is directly connected to the transmission system. . The SDT		

Organization	Yes or No	Question 5.3 Comment
revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your positive comment.		
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: Thank you for your comments.		
SERC Engineering Committee Planning Standards Subcommittee	Yes	These values seem to be in the appropriate range.
Response: Thank you for your comments.		
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: Thank you for your comments. The drafting team agrees that fewer DDRs are required than SOE and FR.		
Florida Power & Light	Yes	We generally agree with this, however, it needs some defining.
Response: Thank you for your comments.		
Cowlitz County PUD	Yes	Again, I feel the burden of proof should be on those who would argue for more stringent criteria.

Organization	Yes or No	Question 5.3 Comment
Response: Thank you for your comments.		
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: Thank you for your comments.		
FirstEnergy	Yes	
MRO NERC Standards Review Subcommittee	Yes	
NYISO	Yes	
Tri-State Generation and Transmission Association	Yes	
US Bureau of Reclamation	Yes	
Portland General Electric	Yes	
PG&E System Protection	Yes	
Puget Sound Energy	Yes	

Organization	Yes or No	Question 5.3 Comment
NextEra Energy Resources (formerly FPL Energy)	Yes	
Manitoba Hydro	Yes	
Exelon Generation LLC	Yes	
NV Energy	Yes	
Wisconsin Electric	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project	Yes	
Progress Energy Florida	Yes	
New York Independent System Operator	Yes	
San Diego Gas and	Yes	

Organization	Yes or No	Question 5.3 Comment
Electric Co.		
SPP System Protection and Control Working Group	Yes	
Tucson Electric Power	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	
British Columbia Transmission Corporation	Yes	
PacifiCorp	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 5.3 Comment
PNM	Yes	
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: Thank you. The drafting team agrees with your comments.		
Schneider Electric		
DTE Energy/Detroit Edison		
Brazos Electric Power Cooperative, Inc.		
WECC		
National Grid		
Pacific Northwest National Laboratory		
E.ON U.S.		

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: Commenters suggested that R3 be separated into two requirements, one for TOs and one for GOs. They questioned the technical justification for the 4millesecond requirement, and found 4milleseconds in requirement R3 confusing when compared to the +/- 2milleseconds requirement in R12. Commenters also asked for clarification regarding TO and GO responsibility in relation to statements with the clause “process to derive.”

The drafting team discussed requirements R3 and R12 and determined that only one time stamping requirement was needed. Therefore, R3 was removed from the standard. R12 is now R1 and applies to both TOs and GOs. The drafting team does not believe that a separate time stamping requirement for TOs and GOs is needed. The drafting team also discussed the clause “a process to derive” at length, agreed that it was not clear, and changed the requirements appropriately. Rather than having a process in place to derive, the drafting team chose to require monitoring of electrical quantities in order to determine three-phase voltage and current of monitored elements. The drafting team believes that this clarifies the intent of the standard.

Organization	Yes or No	Question 6 Comment
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: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
Bonneville Power Administration	No	BPA believes 2-4 second SCADA/EMS records are good enough for most events.
Response: Thank you for your comments. The drafting team agrees that the 2-4 second SCADA/EMS records are generally good for most events, but as identified in the 2003 blackout report, it has been difficult to align the many events due to inconsistent time stamping. In the “August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts” report of February 10, 2004, Recommendation 12 states, “All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning Satellite (GPS).” The point of observation is typically at the substation; therefore, it is recommended that the time synchronization be applied at the substation. The +/- 2		

Organization	Yes or No	Question 6 Comment
millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
FirstEnergy	No	To allow for some flexibility and consistent with other requirements, we recommend replacing 4 ms with 1/4 cycle.
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
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: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
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: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
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: Thank you for your comments. The requirements identify the responsible entities required to have the data. It is up to that responsible entity to determine how the data is generated.		
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.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
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: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
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: Thank you for your comments. The SDT agrees, and the revised standard has separate requirements for TOs and GOs where applicable.		
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: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
SERC Protection and Controls Sub-committee	Yes	Suggest in R3, for consistency, use similar terminology to R12 (where reference is +/- 2 ms).
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
Florida Power & Light	Yes	However, please view our comments for question 17.
Response: Thank you. Please see response to question 17.		
Arizona Public Service Co.	Yes	This is not consistent with requirement R12 which states +/- 2 ms since within 4 ms means +/- 4.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
JEA	Yes	Local 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: Thank you for the comments. The standards requires timestamp of the mechanical contact locally but what type of contact is not defined.		
Alberta Electric System Operator	Yes	The AESO supports the IRC SRC comments to this question.
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
Duke Energy	Yes	Suggest in R3, for consistency, use similar terminology to R 12 (where reference is +/- 2 ms).
Response: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
Northeast Power Coordinating Council	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
PacifiCorp	Yes	
Dominion	Yes	
MRO NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 6 Comment
PG&E System Protection	Yes	
US Bureau of Reclamation	Yes	
NERC	Yes	
Grant County PUD	Yes	
NYISO	Yes	
Cowlitz County PUD	Yes	
Portland General Electric	Yes	
Progress Energy Florida	Yes	
American Electric Power	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Manitoba Hydro	Yes	
NV Energy	Yes	
ITC Transmission, METC	Yes	
City of Tallahassee (TAL)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project	Yes	

Organization	Yes or No	Question 6 Comment
Progress Energy Carolina, Inc.	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
Entergy Services, Inc	Yes	
Northeast Utilities	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
Tucson Electric Power	Yes	
Beckwith Electric Co	Yes	
Xcel Energy	Yes	
Utility System Efficiencies, Inc.	Yes	
British Columbia Transmission Corporation	Yes	
PNM	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: Thank you for your comments. Based on industry comments, the drafting team recognized that this requirement was confusing. It has been removed from the revised standard.		
TransAlta		

Organization	Yes or No	Question 6 Comment
Schneider Electric		
Wisconsin Electric		
DTE Energy/Detroit Edison		
Los Angeles Department of Water & Power		
Puget Sound Energy		
WECC		
National Grid		
Pacific Northwest National Laboratory		
CenterPoint Energy		

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: The majority of commenters did not agree with SOE requirements under R1 through R3. Comments suggested increasing the number of lines criterion to a quantity of five or greater. Also, commenters suggested that the generator nameplate size requirements be lowered to 50 MVA unit or 300 MVA plant. Additionally, commenters stated that the location criteria seemed arbitrary and suggested that it be derived from stability studies of the electric grid with a NERC-defined methodology.

In response to these and other comments, the drafting team undertook a significant rewriting of the draft standard. The requirement language was changed for clarity and the tables were eliminated. To determine location criteria, a task team was formed to develop a technical basis for the requirements. Based on data received,the task team developed location criteria for SOE and FR data to be 25% of bus locations with the highest calculated short circuit MVA level.

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: Thank you for your comments. The SDT believes that to establish SOE circuit breaker position is adequate; however, any additional information, such as protective relay tripping, could provide further insight in the event analysis.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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

Organization	Yes or No	Question 7 Comment
		200 kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. Please see our response for questions 1, 4, and 5.3. The SDT understands your concern related to the location of disturbance monitoring equipment and it is shared by others. In order to develop a continent-wide standard, it is necessary to develop criteria that are measurable. The team's opinion is that if location of DME is done by stability study alone, it will not be measurable. The team evaluated developing a location criteria using three-phase chort circuit MVA criteria based on data collected from select utilities in different regions to determine monitoring requirements. The revised draft of the standard is based on these criteria.		
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: Thank you for your comments. Please see the response in #4. The +/- 2 millisecond is in reference to time stamping. The 4 millisecond requirement relates to ability of the recording equipment to recognize a change to an input status.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. Also see the response to 4 above.		
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: Thank you for your comments. The drafting team agrees that the 2-4 second SCADA/EMS records are generally good for most events, however, as identified in the 2003 blackout report, it was difficult to align the many events due to inconsistent time stamping. In the "August 14, 2003 Blackout: NERC Actions to		

Organization	Yes or No	Question 7 Comment
Prevent and Mitigate the Impacts of Future Cascading Blackouts" report of February 10, 2004, Recommendation 12 states; "All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning Satellite (GPS)." The point of observation is typically at the substation; therefore, it is recommended that the time synchronization be applied at the substation. The +/- 2 millisecond requirement is a time source requirement and is already FERC-approved in PRC-018-1 Requirement R1.1.		
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 requirement be for substations with five or more lines operated at 200 kV or above.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments. The team believes that establishing SOE circuit breaker position is adequate; however, any additional information, such as protective relay tripping, could provide further insight in the event analysis. The generation size requirements have been changed.		
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: Thank you for your comments. To address concerns regarding location criteria the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. Since the tripping of a low voltage generator circuit breaker will have the same effect as tripping the circuit breaker that connects the GSU to the grid, the SDT believes it is reasonable to require monitoring on the low voltage circuit breaker.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		

Organization	Yes or No	Question 7 Comment
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: Thank you for your comments. The SDT agrees and has revised the standard to clarify that recording is the responsibility of the entity that owns the equipment.		
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: Thank you for your comments. The intent of monitoring generator circuit breakers is to determine when a generator is connected to the grid. Since the tripping of a low voltage generator circuit breaker will have the same effect as tripping the high side circuit breaker that connects the GSU to the grid, the SDT believes it is reasonable to require monitoring of both circuit breakers.		
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: Thank you for your comments. The standard has been reworded to require the owner of the circuit breaker to do the monitoring of the circuit breaker status.		
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.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. The proposed standard refers to individual generators of 500 MVA with a combined generation at site of 1500 MVA. The generation size requirements have been changed.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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 only include the >200kV circuit breaker SER data.
Response: Thank you for your comments. The intent of monitoring generator circuit breakers is to determine when a generator is connected to the grid. Since the tripping of a low voltage generator circuit breaker will have the same effect as tripping the high side circuit breaker that connects the GSU to the grid, the SDT believes		

Organization	Yes or No	Question 7 Comment
it is reasonable to require monitoring of both circuit breakers.		
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: Thank you for your comments. The team believes that establishing SOE circuit breaker position is adequate; however, any additional information, such as protective relay tripping, could provide further insight in the event analysis.		
Brazos Electric Power Cooperative, Inc.	No	Need to add clarity to the criteria and do not reference Tables for requirements.
Response: Thank you for your comments. The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
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: Thank you for your comments. The team believes that establishing SOE circuit breaker position is adequate; however, any additional information such as protective relay tripping could provide further insight in the event analysis.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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 CB positions, protective relay tripping for all protection groups and teleprotection keying and receiving.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comments. The team believes that establishing SOE circuit breaker position is adequate; however, any additional information, such as protective relay tripping, could provide further insight in the event analysis. The generation size requirements have been changed.		
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: Thank you for your comments. The intent of the standard is to provide information to analyze system disturbances.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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 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

Organization	Yes or No	Question 7 Comment
		as breaker interrupting / operating time.
Response: Thank you for your comments. While fault recorder data only may be sufficient for the analysis of most events, during major disturbances more detailed sequence of events information is required. The standard has been written to describe what quantities are needed, not what type of equipment is required to do the monitoring. Using a DFR to record SOE data is acceptable if it meets the timing and time synchronization requirements.		
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: Thank you for your comments. The standard has been revised to require the owner of the circuit breaker to monitor the status.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
PNM	No	The defining sum of lines and transformers should be 4 instead of 3. The sum of 3 will exclude few sites.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on data received and established revised criteria for the location of DME that includes short circuit MVA		

Organization	Yes or No	Question 7 Comment
criteria. This is included in the revised draft standard.		
Alberta Electric System Operator	Yes	The AESO supports the IRC SRC comments to this question.
Response: Thank you for your comments. Please see the response to the comments of the IRC Standards Review Committee.		
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: Thank you for your comments. If SCADA logs meet the timing requirements as stated in the standard – and many do – SCADA can be used for sequence of events.		
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: Thank you for your comments. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
American Electric Power	Yes	
MRO NERC Standards Review Subcommittee	Yes	
NV Energy	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Cowlitz County PUD	Yes	
Schneider Electric	Yes	

Organization	Yes or No	Question 7 Comment
PHI (PEPCO Holdings Inc.)	Yes	
Entergy Services, Inc	Yes	
Florida Power & Light	Yes	
Beckwith Electric Co	Yes	
Duke Energy	Yes	
Kansas City Power & Light	Yes	
JEA	Yes	
US Bureau of Reclamation	Yes	
Independent Electricity System Operator	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
Manitoba Hydro	Yes	
Grant County PUD	Yes	
ITC Transmission, METC	Yes	
FirstEnergy	Yes	
SPP System Protection and Control Working Group	Yes	
Pacific Northwest National Laboratory		

Organization	Yes or No	Question 7 Comment
National Grid		
TransAlta		
Los Angeles Department of Water & Power		
WECC		

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: While a majority of commenters supported these pre trigger and post trigger lengths, there were some requests for clarification, which the standard drafting team has addressed. Other commenters requested a definition for an event and asked what determines the final cycle of the event.

The drafting team undertook a significant rewriting of the draft standard. The requirement language was modified for clarity and the term "event" was removed. To determine location criteria, a task team was formed to develop a technical basis for the requirements; that basis is included in the revised draft standard.

Organization	Yes or No	Question 8 Comment
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

Organization	Yes or No	Question 8 Comment
		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: Thank you for your comments. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate. The value of 16 samples was chosen because all but the oldest microprocessor based relays sample at this rate or higher. The standard has been revised to clarify TO and GO requirements.		
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: Thank you for your comments. The SDT received strong support in the first posting for the requirement as written. No change made in that respect.		
SERC Engineering Committee Planning Standards Subcommittee	No	It is not clear why there are two different requirements for sampling data.
Response: Thank you for your comments. If you are referring to the differences in the sampling rates for fault records and DDRs, the differences are related to the data requirement differences between those two types of events.		
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: Thank you for your comments. On a large interconnected system, most faults will be recorded by multiple devices, including devices capable of recording longer records. The SDT believes that adequate information will be recorded and these fault record lengths have been selected to allow for legacy equipment.		

Organization	Yes or No	Question 8 Comment
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: Thank you for your comments. The "final cycle of an event" requirement was intended to determine when a fault cleared, and "an event" has been changed to "the fault.". The final cycle of an event is the last electrical cycle that fault current was flowing. Requiring a two-second record length, or requiring the installation of a device that will continuously record until a fault clears, will eliminate the use of all but the latest generation of microprocessor based relays, and most legacy DFRs. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate. In addition, the newer equipment installed at locations that previous had no equipment will have that capability, and are likely to record events one or more substations away, and that data will help in event analysis.		
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: Thank you for your comments. The standard drafting team thinks that the requirement as worded makes clear that the minimum number of cycles is 52: 50 cycles post-trigger and a pre-trigger record length of two cycles.		
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
Response: Thank you for your comments. The standard drafting teams does not think that "trigger" and "event" are interchangeable. Since this requirement is related to fault recording, the event is a fault that occurred. The trigger is a setting in the recording device that causes the device to record the event. The intent of this wording was to be able to determine when a fault started, and when it ended, while allowing legacy microprocessor based relays and legacy DFRs to be used to meet the standard. On a large interconnected system, most faults will be recorded by multiple devices, including devices capable of recording longer records. If the fault lasts for more than 50 cycles, there will likely be multiple records initiated by a DFR, and very likely a microprocessor based relay that clears the fault.		
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: Thank you for your comments. Since this requirement is related to fault recording, the event is a short circuit that occurred. The trigger is a setting in the recording device that causes the device to record the event. The term "Disturbance" used in Requirement R13 of draft 2 of the standard is the NERC Glossary term.		
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: Thank you for your comments. The term "event" has been removed from the draft standard.		
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.
Response: Thank you for your comments. You are correct in the assumption that the second option was added to allow the use of legacy microprocessor based relays and legacy DFRs. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate.		
E.ON U.S.	No	Generally, pre-trip data has more analytical value than post-trip data.
Response: Thank you for your comments. The standard does not address trip data, rather data gathered for a triggered event. The value of pre-trigger data versus post-trigger data depends on what you are trying to analyze. The standard does not preclude anyone from recording additional pre or post trigger data.		
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

Organization	Yes or No	Question 8 Comment
		this requirement, as presently written.
Response: Thank you for your comments. The requirements were drafted to allow for the use of as many legacy recording devices as possible while still providing adequate information to analyze faults.		
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: Thank you for your comments. See our response to the IRC SRC. Requiring at least 50 cycles would prevent the use of most protective relays which have proven adequate for most events. In the rare event that a fault lasts more than 50 cycles, it is likely that other protective relays and other DFRs will also record the fault.		
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 length to at least 5 sec with pre and post trigger length selectable based on the triggering mechanism.
Response: Thank you for your comments. After a review of triggering practices among many utilities, the SDT decided to allow companies to continue to use whatever method they have found to work well for them. What works for one TO or GO may or may not work for another TO or GO. The drafting team did; however, add a requirement that requires TOs and GOs to have a triggering methodology. The drafting team feels that this requirement does not prescribe what to trigger for, but rather makes sure that the responsible entities have an established methodology to trigger for events. Once the generator is islanded from the transmission system within the time frame specified, the intent of the standard is to capture wide area events. The generator scenario provided does not have a wide area impact. The standard states that: "A pre trigger record length of at least two cycles and a post trigger record length of at least 50 cycles for the same trigger point OR at least two cycles of the pre trigger data; the first three cycles of the fault; and the final cycle of the fault." An entity is able to record a longer data length as long as it meets the requirement above.		
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

Organization	Yes or No	Question 8 Comment
		in every instance. Recommend the SDT consider changing to capturing 6 cycles.
Response: Thank you for your comments. The SDT feels that this is a sufficient for recording most events.		
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: Thank you for your comments. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate.		
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: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Southern Company - Transmission	Yes	No further comment.
Response: Thank you.		
SERC Protection and Controls Sub-committee	Yes	Add to the end of the first bullet for the same trigger point?
Response: Thank you for your comments. The standard has been revised to include your suggestion.		
Dominion	Yes	Add to end of first bullet under R6.1 "for the same trigger point"
Response: Thank you for your comments. The standard has been revised to include your suggestion.		
Bonneville Power Administration	Yes	The number of element criteria may be too stringent, change to 5 elements.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit		

Organization	Yes or No	Question 8 Comment
MVA criteria. This is included in the revised draft standard.		
Florida Power & Light	Yes	We agree, however, the term "event" needs to be defined. Please provide a working definition for event.
Response: Thank you for your comments. The term “event” has been removed from the draft standard.		
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: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. “An event” has been changed to “the fault” in the revised standard.		
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: Thank you for your comments. This can be done in microprocessor based relays by recording two or more records and by using appropriate triggers.		
Tri-State Generation and Transmission Association	Yes	How is the final cycle of an event determined?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing.		
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: Thank you for your comments. It is likely that new protective relays will be able to record the longer records, but the SDT did not want to prescribe in the standard that all new protective relay schemes use the latest available protective relays.		
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: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle		

Organization	Yes or No	Question 8 Comment
that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Puget Sound Energy	Yes	The term final cycle of an event is unclear. What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
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: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
Salt River Project	Yes	What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
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: Thank you for your comments. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate.		
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: Thank you for your comments. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven to be adequate.		
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.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
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: Thank you for your comments. The term "event" refers to a fault (e.g. short circuit) recorded by a fault recorder. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
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: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
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: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
British Columbia Transmission Corporation	Yes	What is the definition of the "final cycle of an event"?
Response: Thank you for your comments. This requirement was intended to determine when a fault cleared. The final cycle of an event is the last electrical cycle that fault current was flowing. "An event" has been changed to "the fault" in the revised standard.		
US Bureau of Reclamation	Yes	
Exelon Generation LLC	Yes	
Entergy Services, Inc	Yes	
PHI (PEPCO Holdings Inc.)	Yes	

Organization	Yes or No	Question 8 Comment
NextEra Energy Resources (formerly FPL Energy)	Yes	
Manitoba Hydro	Yes	
ITC Transmission, METC	Yes	
NV Energy	Yes	
Xcel Energy	Yes	
FirstEnergy	Yes	
American Electric Power	Yes	
Schneider Electric	Yes	
Duke Energy	Yes	
Grant County PUD	Yes	
Wisconsin Electric	Yes	
PNM	Yes	
PacifiCorp	Yes	
Pacific Northwest National Laboratory		
WECC		
Brazos Electric Power Cooperative, Inc.		

Organization	Yes or No	Question 8 Comment
National Grid		
DTE Energy/Detroit Edison		
TransAlta		
Los Angeles Department of Water & Power		
CenterPoint Energy		

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: Comments indicated that the majority of respondents disagreed with Fault Recording requirements under R4 through R6. Commenters suggested increasing the number of lines criteria to a quantity of five or greater. Additionally, commenters pointed out that FR triggering requirements are not addressed.

To address these concerns, the drafting team undertook a significant rewriting of the draft standard. The requirement language was made clearer and the tables were eliminated. To determine location criteria, a task team was formed to develop a technical basis for the requirements. Based on data received, the task team developed location criteria for SOE and FR data to be 25-percent of bus locations with the highest calculated short circuit MVA level.

After a review of triggering practices among many utilities, the SDT decided to allow companies to continue to use whatever method they have found to work well for them. The drafting team did, however, add a requirement that requires applicable owners to have a triggering methodology. The drafting team feels that this requirement does not prescribe for what to trigger, but rather makes sure that the responsible entities have an established methodology to trigger for events.

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: Thank you for your comments. Monitoring of all three phases is necessary for the analysis of all fault types. Monitoring all three phases, or two phases and the residual, will provide enough data to determine all three phases and the residual. The drafting team will consider developing an FAQ document to clarify		

Organization	Yes or No	Question 9 Comment
voltage monitoring requirements on ring buses and breaker-and-a-half arrangements. The standard is also being revised to more clearly indicate what equipment each GO and TO must monitor. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven adequate.		
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: Thank you for your comments. They were not intended to be interpreted as independent requirements; the SDT undertook a significant rewriting of the draft standard to provide clarification.		
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.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. The recording of every line and bus voltage is not explicitly stated. What is stated is that the voltages must be able to be determined. As long as an adequate number of voltages are recorded, such as every other bus or line on a ring bus, and circuit breaker position is known, all voltages can be determined. How an individual company chooses to comply with the requirements may vary from one GO or TO to the next. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		

Organization	Yes or No	Question 9 Comment
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. There are multiple ways to determine every line and every bus voltage. If the two sets of bus voltages in a breaker-and-a-half scheme are recorded, and the status of every circuit breaker is known, all bus and line voltages can be determined.		
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: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually. The SDT has revised the standard to more clearly differentiate GO and TO monitoring requirements.		
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 ensure that sufficient quantities are available to perform any required calculations.
Response: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually.		
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.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. If all of the generation is connected to a single transmission line, the currents and voltages may be monitored at the point of interconnection since this will be the same as the total plant output.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Independent Electricity System Operator	No	Please see our comments on R6, above.
Response: Thank you. See our response to R6 above.		
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

Organization	Yes or No	Question 9 Comment
		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: Thank you for your comments. Your recommendation for voltage locations to be monitored has been incorporated into the latest revision of the standard. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard. The standard is specifically worded to allow recording of voltages and currents on either side of a GSU. The SDT doesn't agree with your recommendation about changing the single generating unit level to 750MVA, thus the single generator nameplate rating remains at 500 MVA or above.		
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

Organization	Yes or No	Question 9 Comment
		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 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: Thank you for your comments. 1) The standard is being revised to clearly indicate what equipment each GO and TO should monitor. 2 and 3) If your GSU is delta on the low side and wye on the high side, the GSU neutral current cannot be determined by summing the three phase currents on the low side. The neutral current can be determined by summing the three phase currents on the high side. The intention of the standard is to tell each GO and TO what quantities are needed, not how to record them, since each entity may use a different approach that suits their needs. 4) The standard has been modified to explicitly state what equipment a GO and TO is to monitor.		
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: Thank you for your comments. The standard has been modified to indicate that either high or low side voltages and current can be recorded. The standard has been revised so that parallel GSUs can be monitored at a common point or individually. If all of the generation is connected to a single transmission line, the currents and voltages may be monitored at the point of interconnection, since this will be the same as the total plant output.		
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

Organization	Yes or No	Question 9 Comment
		requirement?
Response: Thank you for your comments. The standard is being revised to clearly state that a GO is to monitor equipment that the GO owns, and the TO is to monitor the equipment the TO owns. Yes, this is the intent of Requirement 5.2.		
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".
Response: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually. R7 is only for dynamic disturbance recording, not for fault recording, so there is no conflict. Your assumption is incorrect regarding transformation and number of lines. The standard does not address sites but rather Transmission switching stations, transmission substations, generating stations, HVAC converter stations, HVDC converter stations.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Progress Energy Carolina, Inc.	No	Monitoring of GSU transformer currents on units >500MVA is the correct approach. However peaking

Organization	Yes or No	Question 9 Comment
		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: Thank you for your comments. If all of the generation is connected to a single transmission line, the currents and voltages may be monitored at the point of interconnection, since this will be the same as the total plant output.		
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 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: Thank you for your comments. Monitoring of all three phases is necessary for the analysis of all fault types. Monitoring all three phases, or two phases and the residual, will provide enough data to determine all three phases and the residual. The drafting team will consider developing an FAQ document to clarify voltage monitoring requirements on ring buses and breaker-and-a-half arrangements. The standard is also being revised to more clearly indicate what equipment each GO and TO must monitor. The standard was written to allow for the use of legacy equipment. With time stamping added, legacy equipment that meets the draft standard's (PRC-002-2) requirements should be adequate for the analysis of most system disturbances. The SDT believes that installing new equipment at locations that do not have any monitoring is more beneficial than replacing legacy equipment that is currently in use and has proven adequate.		
Brazos Electric Power Cooperative, Inc.	No	Clarify criteria and remove Tables.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. The drafting team agrees that the wording and tables in the standard require clarification. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
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: Thank you for your comments. Adequate fault recording requires monitoring of both voltage and current. As long as those voltages can be determined in some manner, the requirements can be met without installing monitoring on every CCVT or VT. Table 4-1 within the draft standard allows for monitoring at remote terminals.		
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: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually. Transformer neutral currents do not necessarily need to be monitored if they can be derived from the three phase currents. Neutral currents are frequently desirable for the analysis of ground faults.		
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.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to derive all voltages without recording every line or bus individually. The SDT is revising the standard to clearly state that the owner of the equipment is to do the monitoring. After a review of triggering practices among many utilities, the SDT decided to allow companies to continue to use whatever method they have found to work well for them. What works for one TO or GO may or may not work for another TO or GO. The drafting team did, however, add a requirement that the applicable owner have a triggering methodology. The drafting team believes that this requirement does not prescribe what to trigger, for but rather makes sure that the responsible entities have an established methodology to trigger for events.		
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.
Response: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response: Thank you for your comments. As stated above to the IRC SRC, they were not intended to be interpreted as independent requirements. The SDT undertook a significant rewriting of the draft standard to provide clarification.		
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: Thank you for your comments. The standard states that those voltages must be able to be determined, not that every line or bus voltage absolutely needs to be recorded. As long as an adequate number of voltages are recorded, and circuit breaker status is known, it is possible to determine all voltages without recording every line or bus individually.		
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

Organization	Yes or No	Question 9 Comment
		the Transmission Owner."
Response: Thank you for your comments. See answer to question 7 above. Additionally, the standard has been revised to clearly what equipment each GO and TO should monitor.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
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: Thank you for your comments. The recording of every line and bus voltage is not explicitly stated in the standard. What is stated is that the voltages must be able to be determined. As long as an adequate number of voltages are recorded, such as every other bus or line on a ring bus, and circuit breaker position is known, all voltages can be determined.		
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

Organization	Yes or No	Question 9 Comment
		low-side generator currents are monitored but not where high-side GSU currents are monitored.
Response: Thank you for your comments. The standard states that these values may be determined, not necessarily monitored. As written, the high side neutral current is only required if low side phase currents are recorded instead of the high side phase currents.		
Dominion	Yes	Re-label heading of table 4-1 to indicate:" for substation equipment owned by Transmission Owner"
Response: Thank you for your comments. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
MRO NERC Standards Review Subcommittee	Yes	Table 5-1 has a type-o - Row 2, Column 2, bullet 1 extra 'd'.
Response: Thank you. This has been corrected.		
PHI (PEPCO Holdings Inc.)	Yes	FR trigering requirements are not addressed.
Response: Thank you for your comments. After a review of triggering practices among many utilities, the SDT decided to allow companies to continue to use whatever method they have found to work well for them. What works for one TO or GO may or may not work for another TO or GO. The drafting team did, however, add a requirement that requires the applicable owner to have a triggering methodology. The drafting team feels that this requirement does not prescribe what to trigger for, but rather makes sure that the responsible entities have an established methodology to trigger for events.		
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: Thank you for your comments. To address concerns regarding location criteria, the SDT formed a task team dedicated to requesting and analyzing transmission system data. The task team analysis was based on the data received and established revised criteria for the location of DME that includes short circuit MVA criteria. This is included in the revised draft standard.		
E.ON U.S.	Yes	The SDT should explain the applicability of this requirement to the GO.
Response: Thank you for your comments. The standard has been revised to clearly state what equipment each GO and TO should monitor.		
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

Organization	Yes or No	Question 9 Comment
		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: Thank you for your comments. The SDT wrote the current recording requirements such that the currents may be determined, not necessarily monitored. It is not possible to derive all three phase quantities and neutral current by recording only two of the four, and the standard was written accordingly.		
SERC Protection and Controls Sub-committee	Yes	Re-label heading of Table 4-1 to indicate: for substation equipment owned by Transmission Owner?
Response: Thank you for your comments. The tables have been eliminated in the revised draft and the requirements have been rewritten to provide clarification.		
Southern Company - Transmission	Yes	No further comment.
American Electric Power	Yes	
NV Energy	Yes	
ITC Transmission, METC	Yes	
Manitoba Hydro	Yes	
Duke Energy	Yes	
Florida Power & Light	Yes	
Schneider Electric	Yes	
Beckwith Electric Co	Yes	

Organization	Yes or No	Question 9 Comment
SPP System Protection and Control Working Group	Yes	
Cowlitz County PUD	Yes	
Grant County PUD	Yes	
JEA	Yes	
FirstEnergy	Yes	
US Bureau of Reclamation	Yes	
Pacific Northwest National Laboratory		
National Grid		
TransAlta		
Los Angeles Department of Water & Power		
PacifiCorp		
SERC Engineering Committee Planning Standards Subcommittee		
WECC		

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: In general, commenters agreed that if a DDR is found to be required at a substation and there is one located one or two substations away, the entity is in compliance without needing to install an additional DDR. However, based on industry comments, the SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations, revised every five years.

Organization	Yes or No	Question 10 Comment
Kansas City Power & Light	No	Does R7 require DDR at all substations one station away from the substation meeting the location requirement?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The requirement to establish DDR locations have been revised and reworded.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		

Organization	Yes or No	Question 10 Comment
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Southern Company - Transmission	Yes	Southern Company restates its objection to the use of arbitrary location requirements.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
SERC Protection and Controls Sub-committee	Yes	Refer to response in 5.3
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The SDT agrees that DDRs are for wide area monitoring. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		

Organization	Yes or No	Question 10 Comment
Florida Power & Light	Yes	This needs to be stated more clearly. Could you provide specific examples as part of FAQs.
Response: Thank you for your comments. The SDT will consider developing an FAQ document.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Cowlitz County PUD	Yes	I find the original verbiage of R7 confusing without the clarifying statement above. I would consider rewording R7.
Response: Thank you for your comments. The requirements to establish DDR locations have been revised and reworded.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
City of Tallahassee (TAL)	Yes	See concern in Q9 for R4.1, Bullet 1.
Response: Thank you. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or		

Organization	Yes or No	Question 10 Comment
Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Entergy Services, Inc	Yes	Agree with the criterion of adjacent station coverage consistent with comments on 5.3.
Response: Thank you for your comment. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
Alberta Electric System Operator	Yes	The AESO supports the IRC SRC comments.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
PacifiCorp	Yes	
Members of the WECC Disturbance Monitoring Work Group	Yes	
Portland General Electric	Yes	

Organization	Yes or No	Question 10 Comment
US Bureau of Reclamation	Yes	
Tri-State Generation and Transmission Association	Yes	
PG&E System Protection	Yes	
Progress Energy Florida	Yes	
NYISO	Yes	
Manitoba Hydro	Yes	
FirstEnergy	Yes	
Independent Electricity System Operator	Yes	
Dominion	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Schneider Electric	Yes	
Wisconsin Electric	Yes	
Exelon Generation LLC	Yes	
DTE Energy/Detroit Edison	Yes	
NV Energy	Yes	
ITC Transmission, METC	Yes	

Organization	Yes or No	Question 10 Comment
PHI (PEPCO Holdings Inc.)	Yes	
Progress Energy Carolina, Inc.	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Salt River Project	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Arizona Public Service Co.	Yes	
San Diego Gas and Electric Co.	Yes	
New York Independent System Operator	Yes	
JEA	Yes	
Tucson Electric Power	Yes	
Northeast Utilities	Yes	
Duke Energy	Yes	
Xcel Energy	Yes	
Beckwith Electric Co	Yes	

Organization	Yes or No	Question 10 Comment
SPP System Protection and Control Working Group	Yes	
Northeast Power Coordinating Council	Yes	
British Columbia Transmission Corporation	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
TransAlta		
National Grid		
Puget Sound Energy		
Brazos Electric Power Cooperative, Inc.		
WECC		
E.ON U.S.		

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: In general, commenters disagreed with the aggregate of 1500 MVA. They supplied a wide range of recommended generator MVA nameplate ratings; The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.

Organization	Yes or No	Question 11 Comment
Hydro-Québec TransEnergie (HQT)	No	a) 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? b) What is the basis for the "two Substations away" criteria?
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
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 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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is		

Organization	Yes or No	Question 11 Comment
installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
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: The SDT does not agree. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
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.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Northeast Power Coordinating Council	No	a) 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? b) What is the basis for the "two Substations away" criteria?
Response: The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
TransAlta	No	To use a specific number may not be appropriate way. Please see the comments in Q4 for justification.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is		

Organization	Yes or No	Question 11 Comment
installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
DTE Energy/Detroit Edison	No	a) Please see comments for 5.1. b) 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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Members of the WECC Disturbance Monitoring Work Group	Yes	a) 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. b) 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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
PacifiCorp	Yes	We agree regarding the facility rating. However, Generator owners and Transmission 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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is		

Organization	Yes or No	Question 11 Comment
installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Dominion	Yes	Reword R8 to indicate clarify that 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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
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 required to record dynamic disturbances.
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
PG&E System Protection	Yes	a) 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. b) 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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		

Organization	Yes or No	Question 11 Comment
Portland General Electric	Yes	a) 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. b) 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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Puget Sound Energy	Yes	a) 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. b) 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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
City of Tallahassee (TAL)	Yes	Same concern with "plant" vs. "site".
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater. Data requirements for TOs and GOs are defined explicitly in the revised standard.		
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.

Organization	Yes or No	Question 11 Comment
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater. Data requirements for TOs and GOs are defined explicitly in the revised standard.		
Tucson Electric Power	Yes	a) 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. b) 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: The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
Utility System Efficiencies, Inc.	Yes	a) 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. b) 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: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater.		
US Bureau of Reclamation	Yes	
MRO NERC Standards Review Subcommittee	Yes	
American Electric Power	Yes	
NYISO	Yes	
Manitoba Hydro	Yes	
Tri-State Generation and Transmission	Yes	

Organization	Yes or No	Question 11 Comment
Association		
Exelon Generation LLC	Yes	
NV Energy	Yes	
Salt River Project	Yes	
Cowlitz County PUD	Yes	
Independent Electricity System Operator	Yes	
NERC	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Schneider Electric	Yes	
Progress Energy Carolina, Inc.	Yes	
Progress Energy Florida	Yes	
Entergy Services, Inc	Yes	
SERC Engineering Committee Planning Standards Subcommittee	Yes	
New York Independent System Operator	Yes	

Organization	Yes or No	Question 11 Comment
SERC Protection and Controls Sub-committee	Yes	
British Columbia Transmission Corporation	Yes	
Xcel Energy	Yes	
Florida Power & Light	Yes	
Duke Energy	Yes	
Alberta Electric System Operator	Yes	
Beckwith Electric Co	Yes	
Kansas City Power & Light	Yes	
ITC Transmission, METC	Yes	
SPP System Protection and Control Working Group	Yes	
JEA	Yes	
Los Angeles Department of Water & Power		
Pacific Northwest National Laboratory		
Brazos Electric Power Cooperative, Inc.		
WECC		

Organization	Yes or No	Question 11 Comment
Grant County PUD		
National Grid		
CenterPoint Energy		

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: In general, commenters disagreed with the 960 sample per second sampling rate (which currently exists as a requirement in PRC-002-1). A technical analysis was performed on DDR sampling and storage rates, and based on this analysis, the drafting team specified a rate of 960 samples per second as the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The drafting team also realized that there was some confusion about sampling rate and storage rate for calculated values. The wording of the standard has been changed to eliminate this confusion.

Organization	Yes or No	Question 12 Comment
Northeast Power Coordinating Council	No	a) Referring to Requirement R7, because of the limitations of legacy equipment, this requirement will not be met. b) 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.

Organization	Yes or No	Question 12 Comment
		c) Referring to Requirement R8.4, the statement in parenthesis "(per each monitored element)" is redundant. We have no comment to Requirement R9. d) Our response to Question 2 deals with Requirement R10. e) 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: Thank you for your comments.

a) The SDT is accounting for legacy equipment through triggered records, reflected in the updated standard.

b,c) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.

d) Please see our response to Question 2

e) The SDT revised the triggering requirements (old Requirement R11). The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT recognizes that there are regional variations in the application of triggers and has determined this is a practical approach. The latest revision of the standard allows legacy equipment to be used providing it meets all other requirements. The standard states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.

Organization	Yes or No	Question 12 Comment
IRC Standards Review Committee	No	a) 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. b) For R10, the implementation caveat should not be part of the requirement. Rather it should be included as part of the Implementation Plan. c) 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: Thank you for your comments. a) The SDT revised the triggering requirements. The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes. b) The SDT agrees with the recommendation and pulled the date from the requirement and will place it in the revised implementation schedule. c) The revised requirements have the Planning Coordinators or Reliability Coordinators select the DDR locations. The Transmission Owners and Generator Owners are requiredto provide DDR functionality at the locations specified by the Planning Coordinators and record data on the specified Elements.		
SPP System Protection and Control Working Group	No	a) 1) Please clarify R 10 and R 11 with respect to date (January 1, 2011). One suggestion is to have R11 listed before R10.2) b) Specify the actual trigger value in R 11.1
Response: Thank you for your comments. a) The SDT pulled the date from the requirement and will place it in the revised implementation schedule The standard applies to legacy equipment that meets the requirements. b) The SDT revised the triggering requirements. The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range.		

Organization	Yes or No	Question 12 Comment
Members of the WECC Disturbance Monitoring Work Group	No	**a)** 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: Thank you for your comments. a) The draft standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.		
PacifiCorp	No	a) 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 Transmission owners. b) Similar to comment 11. above. We also support WECC's comments responsive to this question.
Response: Thank you for your comments. a) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations. b) See response to comments of referenced sections.		
Bonneville Power Administration	No	a) R9.2 Change to clarify "Sampling" (vs. "collecting") at 960 samples/second, in the slide presentation.R11.2 b) 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. c) Change R12 to say "shall time synchronize all of its Allow for additional/future triggers, frequency set point level vs. rate of change. d) Change R11.3 to have record length include pre-trigger event of 30 seconds to 1 minute.
Response: Thank you for your comments. a) The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power		

Organization	Yes or No	Question 12 Comment
flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1. b) & d) The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes. c) The SDT added the word "time" synchronize to now Requirement R1.		
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: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.		
NERC	No	a) R7 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, 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) b) 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.

Organization	Yes or No	Question 12 Comment
Response: Thank you for your comments. The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.		
NYISO	No	We agree with the minimum requirements set in R9 for all DDRs. a) 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. b) 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. c) 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: Thank you for your comments. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		
Portland General Electric	No	a) 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 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: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per		

Organization	Yes or No	Question 12 Comment
second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.		
Puget Sound Energy	No	a) 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: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.		
Schneider Electric	No	a) 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: Thank you for your comments. Captured waveforms are not required or specified for DDR. Sampled input waveforms for DDR are not required to be stored continuously but rather the standard does require the continuous recording of the output according to the date in the implementation schedule. Continuous recording capability is not requirement for FR functionality.		
Independent Electricity System Operator	No	a) 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. b) 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: Thank you for your comments. The SDT revised the triggering requirements. The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range If the recorder does not have continuous recording capability, it shall set to record data for a minimum of three minutes.		
NV Energy	No	a) 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

Organization	Yes or No	Question 12 Comment
		recorder data.
Response: Thank you for your comments. Yes, the format of the submitted data is important. The requirement for the submittal data in a COMTRADE format provides consistency to facilitate the analysis of system disturbances. This information is listed in Section D, 1.5.1 of the draft standard. The team agreed that an entity may use PMUs as DME if it meets the DDR requirements. The team will not address or establish PMU requirements in the standard because the standard is function specific instead of equipment specific. In addition, PMUs are excluded in the approved SAR.		
DTE Energy/Detroit Edison	No	Please see comments for 9.
Response: Thank you for your comments. Please see our response to your comment to Question 9.		
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: Thank you for your comments. The SDT agrees that the requirement is redundant and deleted old Requirement R9 part 9.1.		
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: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.The team agreed that an entity may use PMUs as DME if it meets the DDR requirements. The team will not address or establish PMU requirements in the standard because the standard is function specific instead of equipment specific. The SDT is using the NERC Glossary definition for DME.		
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.

Organization	Yes or No	Question 12 Comment
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.The team agreed that an entity may use PMUs as DME if it meets the DDR requirements. The team will not address or establish PMU requirements in the standard because the standard is function specific instead of equipment specific. The SDT is using the NERC Glossary definition for DME.		
Pacific Northwest National Laboratory	No	a) 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" 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. b) Consider specifying additional triggers in R11.1 (continued frequency offsets, steps in voltage or line flow, manual triggers, . . .)12F. c) 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: Thank you for your comments. a) The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.b) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. c) Requirements state that each Transmission Owner and Generator Owner that has a DDR device functionality that meets the Planning Coordinator or Reliability		

Organization	Yes or No	Question 12 Comment
Coordinator DDR monitoring requirements and does not have continuous recording capability shall set data record lengths at a minimum of three minutes. The standard does not specify pre-trigger or post-trigger lengths for DDR.		
Hydro-Québec TransEnergie (HQT)	No	a) Referring to Requirement R7, because of the limitations of legacy equipment, this requirement will not be met. b) 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. c) Referring to Requirement R8.4, the statement in parenthesis "(per each monitored element)" is redundant. We have no comment to Requirement R9. d) Our response to Question 2 deals with Requirement R10. e) 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: Thank you for your comments. a) SDT is accounting for legacy equipment through triggered records, reflected in the updated standard. b,c) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater. d) See our response to your comment in Question 2. e) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range		
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: Thank you for your comments. The latest revision of the standard states the effective dates for continuous recording. These requirements take effect the first day of the first calendar quarter one year after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required.		
Northeast Utilities	No	a) Referring to Requirement R7, because of the limitations of legacy equipment, this requirement will not be met. b) Referring to Requirement R8, it's possible for remote locations in a system to have a high concentration of

Organization	Yes or No	Question 12 Comment
		generation spread across several busses. It would seem appropriate to require recorders in such areas. c) Referring to Requirement R8.4, the statement in parenthesis "(per each monitored element)" is redundant. d) Referring to Requirement R9.3, does this need to be stored if the values can be derived from the record e) Response to Question 2 deals with Requirement R10. f) 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": g) 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: Thank you for your comments. a) SDT is accounting for legacy equipment through triggered records, reflected in the updated standard. B,c) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that DDR is installed to monitor generating plants adequately with a gross plant/facility nameplate rating of 1,000 MVA or greater. d) To clarify, the standard states the requirement to record electrical quantities specified for DDR data. e) Updated dates are described in the Implementation Plan. f) & g) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		
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.
Response: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.		

Organization	Yes or No	Question 12 Comment
New York Independent System Operator	No	a) (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? b) 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) c) 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: Thank you for your comments. a) Cross Triggering of multiple devices will not be included as a requirement. The future implementation of continuous recording capabilities required in Requirement R24 (old Requirement R10) will eliminate the need for it. b) PRC-002-1 requirements are not mandatory and enforceable. The SDT does not expect that the use of a different date in this proposed standard, PRC-002-2, will deter the present installation of continuous recording equipment for new or retrofit installations as may be required by regional criteria or regional standards. c) SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range.		
E.ON U.S.	No	a) The GO should be required to collect current and voltage data relative to the triggering event (i.e. change of breaker position). b) 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.

Organization	Yes or No	Question 12 Comment
		c) 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: Thank you for your comments. a) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes. b) The requirement for the submittal data in a COMTRADE format provides consistency to facilitate the analysis of system disturbances. Conversion of CSV or plain test to a COMTRADE format should not be an obstacle to data transfer. c) The effective dates have been modified and are determined by the need for Implementation within the five year cycle of locations determined by the Planning Coordinators or Reliability Coordinators.		
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 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: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.		
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: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities.		

Organization	Yes or No	Question 12 Comment
The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response: Thank you. See response to the IRC SRC comments.		
Utility System Efficiencies, Inc.	No	a) 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 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. b) 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: Thank you for your comments. a) The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second" and "Output reporting rate of electrical quantities of at least 30 times per second".. The 960 samples per second requirement presently exists in PRC-002-1.b) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The SDT revised the related requirement by eliminating the need to trigger for rate-of-change of frequency and for oscillation triggers, set to trigger for low frequency oscillations in 0.1 to 4 Hz range. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		

Organization	Yes or No	Question 12 Comment
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: Thank you for your comments. The standard was modified to clarify that it is the storage or reporting of 30 samples per second of the specified quantities. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: “Input sampling rate of at least 960 samples per second” and “Output reporting rate of electrical quantities of at least 30 times per second”.. The 960 samples per second requirement presently exists in PRC-002-1.		
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: Thank you for your comments. The effective dates have been modified and are determined by the need for Implementation within the five year cycle of locations determined by the Planning Coordinators or Reliability Coordinators.		
PNM	No	
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: Thank you for your comments. The standard has been revised to include single phase-neutral or positive sequence voltage.		
Florida Power & Light	Yes	a) 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.

Organization	Yes or No	Question 12 Comment
Response: Thank you for your comments. The SDT clarified that continuous recording is assigned to DDR functionality only and the DDR sampling and storage rate apply.		
Dominion	Yes	a) 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. b) 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 pre-trigger and post-trigger be a minimum of 1 minute each with total record at least 3 minutes
Response: Thank you for your comments. a) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.b) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		
SERC Protection and Controls Sub-committee	Yes	a) To make this clearer, reword R.7 to start with location requirements rather than exceptions. b) 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?).
Response: Thank you for your comments. a) The old Requirement R7 has been revised. The SDT revised the DDR requirement to require that Planning Coordinators or Reliability Coordinators determine the minimum number of DDR locations based on historical peak load in addition to required locations.b) The latest revision of the standard requires that the Planning Coordinator, Reliability Coordinator, Generator Owners,or the Transmission Owners document and apply a triggering methodology. The standard now states that each required DDR devices without continuous recording capability shall set data record lengths at a minimum of three minutes.		
Southern Company - Transmission	Yes	Southern Company supports the comments submitted by the SERC PCS for this question.
Response: Thank you for your comments. See reply to the SERC PCS.		

Organization	Yes or No	Question 12 Comment
MRO NERC Standards Review Subcommittee	Yes	
Grant County PUD	Yes	
Duke Energy	Yes	
US Bureau of Reclamation	Yes	
Beckwith Electric Co	Yes	
Manitoba Hydro	Yes	
Progress Energy Carolina, Inc.	Yes	
Xcel Energy	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Progress Energy Florida	Yes	
American Electric Power	Yes	
FirstEnergy	Yes	
Tri-State Generation and Transmission Association	Yes	
Cowlitz County PUD	Yes	
Exelon Generation LLC	Yes	

Organization	Yes or No	Question 12 Comment
JEA	Yes	
City of Tallahassee (TAL)		No expertise to provide input.
Response: Thank you.		
Wisconsin Electric		
WECC		
CenterPoint Energy		
National Grid		
TransAlta		
Los Angeles Department of Water & Power		
Brazos Electric Power Cooperative, Inc.		
SERC Engineering Committee Planning Standards Subcommittee		

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: While a majority of the responses were in favor of these time synchronization and data retention requirements, there were some requests for clarification. The standard drafting team has addressed those with the following:

- The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.
- The last phrase of Requirement R12 (now Requirement R1), "with the associated hour offset," allows the entities to use whatever time zone (or hour offset) they feel is appropriate as long as the devices are synchronized to a UTC source.
- Disturbance data shall be stored for a minimum of 10 calendar days following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).

Several comments unrelated to the issues above were also received and the standard drafting team provided responses to those comments below.

Organization	Yes or No	Question 13 Comment
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: Thank you for your comments. The last phrase of Requirement R12 (now Requirement R1), "with the associated hour offset," allows the entities to use whatever time zone (or hour offset) they feel is appropriate as long as the devices are synchronized to a UTC source.		
Tri-State Generation and Transmission Association	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
Response: Thank you for your comments. The 10 days required by the standard is a minimum. Entities are free to retain data for longer periods or indefinitely if they choose.		
Wisconsin Electric	No	The intent of R13 is not clear to us. This seems to be a data retention requirement.
Response: Thank you for your comments. R13 is indeed a data retention requirement and is necessary to recreate an event after a Disturbance in a timely fashion. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		
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: Thank you for your comments. The SDT thinks that the definition, while broad, is appropriate for use in the standard.		
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: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
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

Organization	Yes or No	Question 13 Comment
		COMTRADE, and is considering addition of local offset to the COMTRADE .cfg file.
Response: Thank you for your comments. The SDT does not agree with the recommended rewording because UTC with local offset is used by many operating centers.		
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: Thank you for your comments. The SDT has revised the implementation schedule to allow transition time to become compliant with the requirements.		
Arizona Public Service Co.	No	Earlier in R3 you specify +/- 4 ms
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
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: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.
Response: Thank you for your comments. The last phrase of Requirement R12 (now Requirement R1), “with the associated hour offset,” allows the entities to use whatever time zone (or hour offset) they feel is appropriate as long as the devices are synchronized to a UTC source.		
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 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

Organization	Yes or No	Question 13 Comment
		address natural disaster situations.
Response: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		
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: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device). The SDT is using the definition of Disturbance found in the NERC Glossary of Terms.		
Florida Power & Light	Yes	Please see comments for question 17.
Response: Thank you for your comments. Please see response for question 17.		
PG&E System Protection	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
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: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		

Organization	Yes or No	Question 13 Comment
Puget Sound Energy	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard is silent on equipment.		
Salt River Project	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
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: Thank you for your comments. The SDT thinks that the commenter's processing delay concern is related to equipment configuration, and since the standard does not address specific equipment, it falls outside the scope of the SDT. In addition, PMU application is excluded in the SAR.		
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: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		
Tucson Electric Power	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
Duke Energy	Yes	DDR data will overwrite after 10 days, in some instances.
Response: Thank you for your comments. Disturbance data shall be stored for a minimum of 10 calendar days, following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).		

Organization	Yes or No	Question 13 Comment
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: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment. The SDT thinks that the commenter's processing delay concern is related to equipment configuration, and since the standard does not address specific equipment, it falls outside the scope of the SDT. In addition, PMU application is excluded in the SAR.		
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: Thank you for your comments. The SDT is using the definition of Disturbance found in the NERC Glossary of Terms.		
Members of the WECC Disturbance Monitoring Work Group	Yes	The +/- 2 milliseconds requirement is not consistent with the 4 millisecond requirement in R3.
Response: Thank you for your comments. The +/-2 millisecond requirement refers to how closely the recording devices must be synchronized to a UTC Source. The 4 millisecond requirement in Requirement R3 was eliminated from the standard since this standard does not address specific equipment.		
Southern Company - Transmission	Yes	No further comment.
MRO NERC Standards Review Subcommittee	Yes	
Dominion	Yes	
FirstEnergy	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 13 Comment
NERC	Yes	
SERC Protection and Controls Sub-committee	Yes	
US Bureau of Reclamation	Yes	
NYISO	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Manitoba Hydro	Yes	
ITC Transmission, METC	Yes	
Independent Electricity System Operator	Yes	
Grant County PUD	Yes	
American Electric Power	Yes	
Bonneville Power Administration	Yes	
NV Energy	Yes	
Schneider Electric	Yes	
Progress Energy Florida	Yes	
Progress Energy Carolina, Inc.	Yes	

Organization	Yes or No	Question 13 Comment
Hydro-Québec TransEnergie (HQT)	Yes	
Beckwith Electric Co	Yes	
PNM	Yes	
Entergy Services, Inc	Yes	
British Columbia Transmission Corporation	Yes	
Exelon Generation LLC	Yes	
Xcel Energy	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Northeast Power Coordinating Council	Yes	
Cowlitz County PUD	Yes	
SERC Engineering Committee Planning Standards Subcommittee		
TransAlta		
National Grid		
DTE Energy/Detroit Edison		
Brazos Electric Power Cooperative,		

Organization	Yes or No	Question 13 Comment
Inc.		
Los Angeles Department of Water & Power		
WECC		

General Questions

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

Summary Consideration: Commenters were not aware of a variance for this standard at this point of its development. The SDT reminds commenters that entities are not precluded from developing more stringent criteria. Establishing a lower cutoff for a proposed NERC standard requirement is simply a variance of that requirement and not appropriate for inclusion in a regional standard. Any region that believes it is appropriate to establish such levels needs to decide whether developing a regional criteria or submitting it as a variance to the SDT best suits their situation.

Organization	Yes or No	Question 14 Comment
NERC	No	For reasons of consistency in the ability to cross-regional or interconnection-wide disturbance analysis, there should be no regional variances.
Response: The SDT thanks you for your comment.		
DTE Energy/Detroit Edison	No	Will regional variances be included in this standard?
Response: Thank you for your comment. As of this last posting, the SDT had not received any variance requests for this standard.		
Entergy Services, Inc	No	Not as proposed, but there should be for DDR applications.
Response: Thank you for your comment. As of this last posting, the SDT had not received any variance requests for this standard.		
Northeast Power Coordinating Council	No	
IRC Standards Review Committee	No	
SPP System Protection and Control Working Group	No	

Organization	Yes or No	Question 14 Comment
Southern Company - Transmission	No	No further comment.
SERC Engineering Committee Planning Standards Subcommittee	No	
PacifiCorp	No	
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	
Grant County PUD	No	
NYISO	No	
Tri-State Generation and Transmission Association	No	
Cowlitz County PUD	No	Question 14 Comments:
Progress Energy Florida	No	

Organization	Yes or No	Question 14 Comment
Schneider Electric	No	
Independent Electricity System Operator	No	
American Electric Power	No	
NextEra Energy Resources (formerly FPL Energy)	No	
Manitoba Hydro	No	
Exelon Generation LLC	No	
Wisconsin Electric	No	
ITC Transmission, METC	No	
City of Tallahassee (TAL)	No	
NV Energy (fka Sierra Pacific Resources)	No	
Progress Energy Carolina, Inc.	No	
Hydro-Québec TransEnergie (HQT)	No	
Northeast Utilities	No	
New York Independent System Operator	No	
JEA	No	

Organization	Yes or No	Question 14 Comment
Beckwith Electric Co	No	
Duke Energy	No	
Xcel Energy	No	
Kansas City Power & Light	No	
PNM	No	
SERC Protection and Controls Sub-committee	Yes	See comment on response #1.
Response: Thank you for your comments. For Question 1, you commented: "But we believe that the regional "Stability" group needs to decide on the locations of the DDR's based on a NERC defined methodology." Allowing a regional stability group to define the locations is considered a fill-in-the-blank requirement. The SDT formed a task team dedicated to requesting and analyzing transmission system data. The SDT used the task team analysis results to establish revised criteria for locations.		
Dominion	Yes	We support the 200 kV cutoff. However, some regions have indicated the 200kV threshold is not appropriate and 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: Thank you for your comments. Entities are not precluded from developing more stringent criteria. The SDT formed a task team dedicated to requesting and analyzing transmission system data and used the task team analysis results to establish revised criteria for locations.		
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: Thank you for your comment. Since this NERC DM standard has not been fully developed, Reliability*First* can develop and seek approval of its standard in accordance with approved Standard Development Procedures. Reliability*First* is encouraged to track the development of this standard and to consider if it wishes to continue to support and justify a more stringent MVA level of the developing NERC proposal and request a variance accordingly. The SDT formed a task team dedicated to requesting and analyzing transmission system data and used the task team analysis results to establish revised criteria for locations.		

Organization	Yes or No	Question 14 Comment
US Bureau of Reclamation	Yes	
Alberta Electric System Operator	Yes	
NV Energy		As stated previously, the DDR data format differs from region to region and should be standardized.
Response: Thank you for your comment. Data file formatting is not the subject of "what" is required by the standard, but a matter of "how" processes and procedures are developed and communicated. The standard requires that the data be available; the format and how it is communicated are at the discretion of the users.		
Puget Sound Energy		
National Grid		
Members of the WECC Disturbance Monitoring Work Group		
Pacific Northwest National Laboratory		
Salt River Project		
WECC		
Portland General Electric		
TransAlta		
Brazos Electric Power Cooperative, Inc.		
Arizona Public Service Co.		

Organization	Yes or No	Question 14 Comment
San Diego Gas and Electric Co.		
E.ON U.S.		
Tucson Electric Power		
CenterPoint Energy		
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		

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: Commenters were generally unaware of any specific regulatory concerns; however, it was pointed out that the potential incremental financial impact may need to be considered before approval.

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	
Southern Company - Transmission	No	No further comment.
SERC Engineering Committee Planning Standards Subcommittee	No	
SERC Protection and Controls Sub-committee	No	
PacifiCorp	No	
Bonneville Power Administration	No	
FirstEnergy	No	
Florida Power & Light	No	

Organization	Yes or No	Question 15 Comment
Los Angeles Department of Water & Power	No	
MRO NERC Standards Review Subcommittee	No	
NERC	No	
NYISO	No	
Tri-State Generation and Transmission Association	No	
Cowlitz County PUD	No	
Progress Energy Florida	No	
Schneider Electric	No	
Independent Electricity System Operator	No	
NextEra Energy Resources (formerly FPL Energy)	No	
Manitoba Hydro	No	
Exelon Generation LLC	No	
NV Energy	No	
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	
Progress Energy Carolina, Inc.	No	
Hydro-Québec TransEnergie (HQT)	No	
Entergy Services, Inc	No	
Northeast Utilities	No	
New York Independent System Operator	No	
JEA	No	
Alberta Electric System Operator	No	
Beckwith Electric Co	No	
Duke Energy	No	
Xcel Energy	No	
Kansas City Power & Light	No	
Dominion	Yes	Concern that FERC standards and code of conducts, as well as some RTO/ISO rules may prohibit the GO from access to system monitoring data necessary to participate in disturbance analysis studies.
Response: Thank you for your comment. The purpose of this standard is to ensure that disturbance data is available and does not establish requirements for disturbance analysis studies. The conditions under which the data is used, why it is used, and by which entity it is used are as diverse as the range of disturbances and system configurations. Since neither this standard, nor its predecessors, established "what" analyses are required and by which entity, it was not possible to		

Organization	Yes or No	Question 15 Comment
establish reporting "requirements" which are really a matter of "how" the available information can be communicated and utilized.		
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: Thank you for your comment. The SDT understands your concern in the context of FERC-approved PRC-018-1, which required adding time synchronization. The extent of incremental installations resulting from approval of this standard over that resulting from current standards and criteria is unknown at this time, as the SDT is still developing the technical requirements. This standard is being developed to address reliability issues and serves to improve reliability; therefore, associated implementation costs should be justifiable.		
US Bureau of Reclamation	Yes	
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 standard proposes.
Response: Thank you for your comment. The SDT is unable to determine from your comments whether the WECC requirements are more stringent. If those requirements are more stringent, the proposed standard requirements would not preclude those regional requirements from continuing. The entities would have only to demonstrate that they meet the standard requirements.		
PG&E System Protection		
TransAlta		
Puget Sound Energy		
DTE Energy/Detroit Edison		
Portland General Electric		
National Grid		

Organization	Yes or No	Question 15 Comment
Wisconsin Electric		
Pacific Northwest National Laboratory		
Salt River Project		
WECC		
San Diego Gas and Electric Co.		
E.ON U.S.		
Members of the WECC Disturbance Monitoring Work Group		
Tucson Electric Power		
Brazos Electric Power Cooperative, Inc.		
CenterPoint Energy		
Grant County PUD		
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		
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: Commenters provided a wide range of additional questions and comments. A majority of those comments are addressed as follows:

- Compliance Section 1.3.2 and 1.5 are in the Compliance section because they are supporting documentation to demonstrate compliance with the requirements.
- TOs and GOs are required to document and apply a triggering methodology for FR and DDR in the latest revision of the standard.
- The SDT revised the requirements to split the TO and GO requirements into separate requirements to more distinctly address ownership. The standard cannot address all issues with joint ownership. It is up to the owners to address these issues.
- The purpose of the standard is to ensure that data is available to analyze wide area events. Natural disasters may generate large amounts of data and the TO or GO is expected to have that data available. The standard does not state that all of the monitoring equipment must produce data for every event. In the event that a natural disaster, which is considered an act of god, destroys the monitoring equipment and data is not available, as long as data is available from other monitoring location, the intent of the standard's requirements is still met.

Organization	Yes or No	Question 16 Comment
Cowlitz County PUD	No	Typo above, it is 16.
Response: The SDT does not understand this comment.		
ITC Transmission, METC	No	
NV Energy (fka Sierra Pacific Resources)	No	
Arizona Public Service Co.	No	
Manitoba Hydro	No	

Organization	Yes or No	Question 16 Comment
Tri-State Generation and Transmission Association	No	
US Bureau of Reclamation	No	
Wisconsin Electric	No	
NV Energy	No	
Beckwith Electric Co	No	
Florida Power & Light	No	
NextEra Energy Resources (formerly FPL Energy)	No	
JEA	No	
SERC Protection and Controls Sub-committee	No	
PHI (PEPCO Holdings Inc.)	No	
SERC Engineering Committee Planning Standards Subcommittee	No	
Southern Company - Transmission	No	No further 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

Organization	Yes or No	Question 16 Comment
		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: Thank you for your comment. The standard has been revised to eliminate voltage level and generation size from the applicability section. Table 2-1 has been removed. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses.		
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: Thank you for your comment. The SDT considered this comment but decided to leave these items in the compliance section. The standard requirements should focus on the "what" and not the "how". In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard.		
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: Thank you for your comment. 1. The proposed standard has been revised to add triggering requirements related to a fault on the transmission system. 2. The SDT has retained these items in the compliance section. 3. The Transmission Owner or Generator Owner can ensure that disturbance monitoring is furnished by contract with the other party.		
Members of the WECC Disturbance Monitoring Work Group	Yes	1. Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. 2. 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. 3. 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.

Organization	Yes or No	Question 16 Comment
Response: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the stated format. The proposed standard will retain this requirement.		
PacifiCorp	Yes	1. 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. 2. 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: Thank you for your comment. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
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

Organization	Yes or No	Question 16 Comment
		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: Thank you for your comment. 1. The proposed standard has been revised to include ownership of the equipment to be monitored in the disturbance monitoring requirements. 2. The SDT considered this comment but decided to leave these items in the compliance section. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard 3. The SDT considered this comment but decided not to change the purpose statement. The title of the standard reflects the reporting objective, but more importantly, the requirements contain the necessary reporting requirements between the entities responsible for DME. 4. The proposed standard has been revised in accordance with your 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: Thank you for your comment. The proposed standard has been revised to require a less aggressive implementation schedule.		
PG&E System Protection	Yes	1. Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units was not. 2. 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. 3. 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

Organization	Yes or No	Question 16 Comment
		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: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
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: Thank you for your comment. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule.		
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 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: Thank you for your comment. The Tables have been removed. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses.		
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"

Organization	Yes or No	Question 16 Comment
Response: Thank you for your comment. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule. The tables have been removed.		
Portland General Electric	Yes	The following comments are those filed by the DMWG which we are filing in support: 1. Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. 2. 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. 3. 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: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
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 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: Thank you for your comment. The standard has been revised to eliminate voltage level and generation size from the applicability section. Table 4-1 has been removed. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses.		

Organization	Yes or No	Question 16 Comment
Puget Sound Energy	Yes	1. Would this standard apply to a combined cycle plant that the total capability was above 500 but each of the individual units were not. 2. 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. 3. 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: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
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: Thank you for your comment. The SDT has considered the differences in recording methods used between vendors and resolved to allow for these vendor differences as long as the data is time stamped and sampled at the required rates or better. The SDT did not consider the IEC standard.		
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 conditions or events.
Response: Thank you for your comment. The proposed standard has been revised to add triggering requirements.		
American Electric Power	Yes	1.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. 2. Section 1.5

Organization	Yes or No	Question 16 Comment
		of the Section D should be moved into the technical requirement portion of the standard. These involve technical considerations. 3. Please remove bullet three (related to interposing relays). 4. 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. 5 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." 6. To be clear, R4.2 (p. 6) should have "one winding of each monitored" added before the word "transformer" in line 2. 7. 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. 8. 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: The SDT thanks you for your comments. 1. The SDT considered this comment but did not revise the proposed standard because the requirements should focus on what is required for reliability and not necessarily consider how they will be met (i.e. via agreement between responsible entities). 2. The SDT chose to retain these in the compliance section. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard. 3. The proposed standard has been revised in accordance with your comment. 4. The SDT plans to add measures with the second formal posting. 5. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule. 6. The SDT considered this comment but did not revise the proposed standard accordingly because the drafting team thinks it is clearly stated in the revised standard. 7. Table 5-1 has been eliminated in the revised standard. 8. The proposed standard has been revised in section A-5 but was not revised on page 2.		
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: Thank you for your comment. 1. Data for required parameters/quantities for 50% of the designated locations to be monitored should be available within two years. 2. PRC-018 will be replaced by the proposed standard. The 75% requirement has been dropped by PRC-002-2. 3. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule.		
DTE Energy/Detroit Edison	Yes	When will violation severity levels be added?
Response: Thank you for your comment. Violation Severity Levels will be added for the second formal posting.		
City of Tallahassee (TAL)	Yes	1. 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. 2. 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: Thank you for your comment. 1. The SDT has revised the standard to clarify this wording in accordance with your comments. 2. The SDT has considered this comment. The SDT chose to retain these in the compliance section. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
Pacific Northwest National Laboratory	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 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

Organization	Yes or No	Question 16 Comment
		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: The SDT thanks you for your comments and appreciates the level of detail in your concerns. The SDT chose to retain the existing proposed standard text in these areas. The standard requirements should focus on the "what" and not the "how". In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
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: Thank you for your comment. The SDT considered the comment but left the proposed standard wording unchanged in this regard. The draft standard was modified to revise the requirement to store calculated electrical quantities at a rate of at least 30 times per second. The specified rate of 960 samples per second is the internal sampling rate of the electrical signal used to achieve the desired metering accuracy for the derived RMS values of voltage, current, and power flow. The SDT clarified the requirement in the standard by adding the words: "Input sampling rate of at least 960 samples per second". The 960 samples per second requirement presently exist in PRC-002-1.		
Hydro-Québec TransEnergie (HQT)	Yes	1. 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. 2. 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.

Organization	Yes or No	Question 16 Comment
Response: Thank you for your comment. 1. Table 2-1 has been removed. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses. 2. The standard has been revised to eliminate voltage level and generation size from the applicability section.		
Entergy Services, Inc	Yes	Seems like Section D.1.5 Additional Compliance Information should be listed as part of the requirements.
Response: Thank you for your comment. The SDT considered this it but decided to leave these items in the compliance sections. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
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: Thank you for your comment. The standard has been revised to eliminate voltage level and generation size from the applicability section. The SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. Also see question 5 responses.		
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: Thank you for your comment. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus.		
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

Organization	Yes or No	Question 16 Comment
		Synchrophasor Standard revision Working Group H11Channel Names and Instrument Names Working Group H10SOE Data Working Groups H5b (completed) and H16
Response: The SDT thanks you for these comments. The SDT chose to retain these in the compliance section. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
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. 2. 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. 3. 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: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement. The standard drafting team did not move the data format requirements into the Requirements section of the standard because the standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard.		
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: Thank you for your comment. The SDT plans to include these compliance elements in the second formal posting of the proposed standard.		
CenterPoint Energy	Yes	1. 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

Organization	Yes or No	Question 16 Comment
		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). 2. 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. 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. 3. 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: Thank you for your comment. 1. This requirement is intended to monitor a circuit breaker 52a or 52b contact. The intent is for the SOE device to record the change of state within 4 milliseconds of this change of state. 2. The SDT considered this comment but decided to retain the items in the compliance section in the revised standard, except that the interposing relay delay reporting has been eliminated. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard 3. Please see the response in question 13.		
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: Thank you for your comment. The SDT considered this comment and determined that the proposed standard will retain these compliance elements. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		

Organization	Yes or No	Question 16 Comment
Utility System Efficiencies, Inc.	Yes	1. 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. 2. 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. 3. 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, resampling, calculation of derived quantities, renaming or selective deletion of signals.
Response: Thank you for your comment. 1. The draft standard posted for this comment period would not apply in this case. However, the SDT performed a technical analysis to determine the location requirements for SOE, FR and DDR data and produced a technical paper summarizing the analysis. The proposed standard has been revised in this area and the case cited may be subject to the standard depending on other factors, such as available short circuit at the facility transmission system bus. 2 and 3. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement.		
British Columbia Transmission Corporation	Yes	1. 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. 2. 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: Thank you for your comment. The SDT considered this comment and determined that DDR data can be provided in the required format. The proposed standard will retain this requirement. The standard requirements should focus on the “what” and not the “how”. In addition, the formatting requirements do not have a		

Organization	Yes or No	Question 16 Comment
direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard		
Kansas City Power & Light	Yes	1. 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. 2. 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: Thank you for your comment. 1. The SDT considered this comment and decided to retain these compliance requirements. The standard requirements should focus on the "what" and not the "how". In addition, the formatting requirements do not have a direct impact on reliability. As a result, the drafting team elected to keep these lower-level facilitating data format requirements in the compliance section of the standard 2. The standard will be revised to provide consistency in compliance requirements and a less aggressive implementation schedule.		
MRO NERC Standards Review Subcommittee	Yes	
Bonneville Power Administration	Yes	
Alberta Electric System Operator	Yes	
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: Thank you for your comment. The proposed standard has been revised in accordance with your comments.		

Organization	Yes or No	Question 16 Comment
Salt River Project		
WECC		
Brazos Electric Power Cooperative, Inc.		
E.ON U.S.		
National Grid		
Grant County PUD		

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: The implementation plan in the revised standard has been modified, and the wording of the percentage of compliance milestones has been clarified.

If older GPS equipment has accuracy problems, it will need to be replaced to meet compliance.

Disturbance data shall be stored for a minimum of 10 calendar days following a Disturbance. This storage can be either local (in the recording device) or remote (in a substation data collection device, company network, or other storage device).

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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one in the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one in the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		

Organization	Yes or No	Question 17 Comment
Bonneville Power Administration	No	It's too fast for a 3 year budget cycle entity.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Florida Power & Light	No	1. 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. 2. 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. 3. 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: Thank you for your comment. 1. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.2. The time accuracy requirement is deemed necessary as a technical requirement to provide data that is adequate for wide area disturbance event		

Organization	Yes or No	Question 17 Comment
analysis. 3. The less aggressive implementation plan should aid in meeting the storage function.		
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: Thank you for your comment. Please see the responses for question 5 above.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to		

Organization	Yes or No	Question 17 Comment
ensure a realistic transition to the new requirements.		
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 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: Thank you for your comment. 1. . Data for required parameters/quantities for 50% of the designated locations to be monitored should be available within two years. 2. PRC-018 will be replaced by the proposed standard. The 75% requirement has been dropped by PRC-002-2. 3. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation		

Organization	Yes or No	Question 17 Comment
plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. PRC-018 will remain in effect until the adoption of this standard. The SDT is not aware of plans to defer PRC-018 compliance.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Alberta Electric System Operator	No	The AESO supports the IRC SRC comments.

Organization	Yes or No	Question 17 Comment
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Southern Company - Transmission	Yes	Southern Company supports the comments submitted by the SERC PCS for this question.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
PacifiCorp	Yes	The time allowed in the draft standard appears acceptable.
Response: The SDT thanks you for your comment.		
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

Organization	Yes or No	Question 17 Comment
		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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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".
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Cowlitz County PUD	Yes	Question 17 Comments: This standard as written will not apply to Cowlitz and therefore will not present a burden.
Response: The SDT thanks you for your comment.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		

Organization	Yes or No	Question 17 Comment
SERC Engineering Committee Planning Standards Subcommittee	Yes	
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
NV Energy	Yes	
City of Tallahassee (TAL)	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Entergy Services, Inc	Yes	
Progress Energy Florida	Yes	
San Diego Gas and Electric Co.	Yes	
Grant County PUD	Yes	
Schneider Electric	Yes	
NV Energy (fka Sierra Pacific Resources)	Yes	
Manitoba Hydro	Yes	
NYISO	Yes	
JEA	Yes	
Beckwith Electric Co	Yes	

Organization	Yes or No	Question 17 Comment
MRO NERC Standards Review Subcommittee	Yes	
Kansas City Power & Light	Yes	
Members of the WECC Disturbance Monitoring Work Group		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
PG&E System Protection		The Effective date information is unclear for the 50% and 100% compliance requirements. Also, how would this implementation plan affect the PRC-018 application?
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements. This standard will replace PRC-018 when adopted.		
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: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Puget Sound Energy		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response: The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Tucson Electric Power		The Effective date information is unclear for the 50% and 100% compliance requirements.

Organization	Yes or No	Question 17 Comment
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Utility System Efficiencies, Inc.		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
PNM		The Effective date information is unclear for the 50% and 100% compliance requirements.
Response: Thank you for your comment. The standard has been revised to ensure consistency with the effective dates in the standard and the implementation plan (now one and the same in the revised version of the standard). The standard drafting team considered required transition time in the revised effective dates to ensure a realistic transition to the new requirements.		
Wisconsin Electric		
New York Independent System Operator		
Brazos Electric Power Cooperative, Inc.		
E.ON U.S.		
TransAlta		
Arizona Public Service Co.		
WECC		
CenterPoint Energy		
Pacific Northwest National Laboratory		

Organization	Yes or No	Question 17 Comment
Salt River Project		
National Grid		
Los Angeles Department of Water & Power		
British Columbia Transmission Corporation		

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: Comments indicate that there is sufficient misunderstanding of the term "Substation" to warrant a definition; however, as several comments pointed out, the IEEE definition of Substation includes a transformer and therefore eliminates what the industry commonly refers to as "switching stations." Because of this, the drafting team agrees that the IEEE definition of Substation is not acceptable for use in this standard.

The drafting team has made significant changes to the standard based on comments received. The new location criteria are based on short circuit levels and eliminate the word "Substation" from the standard.

Organization	Yes or No	Question 18 Comment
Alberta Electric System Operator	No	
Response:		
Duke Energy	No	We agree with the IEEE definition. We don't think that there is sufficient misunderstanding to warrant a NERC definition.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		
IRC Standards Review Committee	No	
Response:		
SERC Engineering Committee Planning Standards Subcommittee	No	There is not sufficient misunderstanding to warrant a definition.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		

Organization	Yes or No	Question 18 Comment
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: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.”		
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: Thank you for your comment. The Standard has been modified to hopefully clarify the location requirement with out using the term “Substation.”		
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: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.” “Interconnected systems” of the TO and GO or multiple TOs will need to have appropriate agreements of responsibility for compliance to the standard requirements, but this is beyond the scope of this standard.		
Progress Energy Florida	No	Clarification is needed whether to include switching stations as part of the criteria (i.e., 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: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these “Switching Substations.” The standard has been modified to clarify the location requirement without using the term “Substation.”		
Bonneville Power Administration	Yes	Also supply the IEEC C37.111-1999 and C37.232-2007 referred to.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.”		
SERC Protection and Controls Sub-committee	Yes	We agree with the IEEE definition.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.”		

Organization	Yes or No	Question 18 Comment
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: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		
Manitoba Hydro	Yes	We agree with the IEEE definition.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term "Substation."		
DTE Energy/Detroit Edison	Yes	A definition is warranted, but the IEEE definition doesn't cover all the configurations that exist.
Response: Thank you for your comment. The Standard has been modified to hopefully clarify the location requirement without using the term "Substation."		
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: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these "Switching Substations." The standard has been modified to clarify the location requirement without using the term "Substation."		
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: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these "Switching Substations." The standard has been modified to clarify the location requirement without using the term "Substation."		
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

Organization	Yes or No	Question 18 Comment
		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: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these “Switching Substations.” The standard has been modified to clarify the location requirement without using the term “Substation.”		
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: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.”		
Southern Company - Transmission	Yes	Southern Company supports the proposed definition of "Substation."
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.”		
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: Thank you for your comment. The SDT agrees that the IEEE definition may not apply to these “Switching Substations.” The standard has been modified to clarify the location requirement without using the term “Substation.”		
Los Angeles Department of Water & Power	Yes	
Grant County PUD	Yes	

Organization	Yes or No	Question 18 Comment
SPP System Protection and Control Working Group	Yes	
NYISO	Yes	
FirstEnergy	Yes	
NERC	Yes	
Cowlitz County PUD	Yes	
Schneider Electric	Yes	
Independent Electricity System Operator	Yes	
PacifiCorp	Yes	
MRO NERC Standards Review Subcommittee	Yes	
NextEra Energy Resources (formerly FPL Energy)	Yes	
Exelon Generation LLC	Yes	
Wisconsin Electric	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 18 Comment
Progress Energy Carolina, Inc.	Yes	
City of Tallahassee (TAL)	Yes	
Entergy Services, Inc	Yes	
Kansas City Power & Light	Yes	
JEA	Yes	
New York Independent System Operator	Yes	
PHI (PEPCO Holdings Inc.)	Yes	
Beckwith Electric Co	Yes	
PNM	Yes	
Xcel Energy		We agree the IEEE definition is appropriate.
Response: Thank you for your comment. The standard has been modified to clarify the location requirement without using the term “Substation.”		
TransAlta		
National Grid		
Tucson Electric Power		
CenterPoint Energy		
PG&E System Protection		

Organization	Yes or No	Question 18 Comment
Puget Sound Energy		
Portland General Electric		
Salt River Project		
Utility System Efficiencies, Inc.		
British Columbia Transmission Corporation		
Pacific Northwest National Laboratory		
San Diego Gas and Electric Co.		
E.ON U.S.		
Arizona Public Service Co.		
NV Energy (fka Sierra Pacific Resources)		
WECC		
Members of the WECC Disturbance Monitoring Work Group		

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Nomination Form

Project 2007-11 Disturance Monitoring
Standard Drafting Team

Please return this form as soon as possible. If you have any questions, please contact Howard Gugel at howard.gugel@nerc.net.

By submitting the following information, you are indicating your willingness and agreement to actively participate in the Standard Drafting Team (SDT) meetings if appointed to the SDT by the Standards Committee. This means that if you are appointed to the SDT, you are expected to attend all (or at least the vast majority) of the face-to-face SDT meetings as well as participate in all the SDT meetings held via conference calls, and failure to do so shall result in your removal from the SDT.

Project 2007-11 Disturbance Monitoring

The purpose of this project is to establish requirements for recording and reporting sequence of events (SOE) data, fault recording (FR) data, and dynamic disturbance recording (DDR) data to facilitate analysis of Disturbances.

We are seeking two individuals who have experience and expertise with disturbance monitoring or power system operations. If possible, we would like to add a member from the RFC Region and Canada.

We are also seeking a lawyer to participate on the team.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted if applicable.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team:
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ ERCOT	☐ NPCC	☐ SPP
☐ FRCC	☐ RFC	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:

☐	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, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority ☐ Compliance Enforcement Authority ☐ Distribution Provider ☐ Generator Operator ☐ Generator Owner ☐ Interchange Authority ☐ Load-serving Entity ☐ Market Operator ☐ Planning Coordinator	☐ Transmission Operator ☐ Transmission Owner ☐ Transmission Planner ☐ Transmission Service Provider ☐ Purchasing-selling Entity ☐ Reliability Coordinator ☐ Reliability Assurer ☐ Resource Planner

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Standards Announcement

Project 2007-11 Disturbance Monitoring Standard Drafting Team

Nomination Period Open through April 25, 2013

Link to Official Nomination Form
Link to Word Version of Nomination Form

Background
The purpose of this project is to establish requirements for recording and reporting sequence of events (SOE) data, fault recording (FR) data, and dynamic disturbance recording (DDR) data to facilitate analysis of Disturbances.

We are seeking two individuals who have experience and expertise with disturbance monitoring or power system operations. If possible, we would like to add a member from the RFC Region and Canada.

We are also seeking a lawyer to participate on the team.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted if applicable.

Instructions for Submitting a Nomination
If you are interested in serving on the Standard Drafting Team, please complete this nomination form by **April 25, 2013**. The nomination form should be submitted describing the individual's experience or qualifications related to the project.

An unofficial Word version of the nomination form is also posted on the Standard Drafting Team Vacancies page.

Standards Process

The Reliability Standards Development Plan explains NERC's work plan for standards development in 2013 and beyond, and the Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our gratitude to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd.NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standard Authorization Request Form – Revised SAR

Request Date	April 15, 2013

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Individual, Group, or Committee Name Project 2007-11 Disturbance Monitoring Standard Drafting Team	☐	New Standard
Primary Contact (if Group or Committee) Lee Pedowicz	☒	Revision to existing Standard
Company or Group Name Northeast Power Coordinating Council	☐	Withdrawal of existing Standard
E-mail lpedowicz@npcc.org	☐	Project Identified in Reliability Standards Development Plan (Project Number and Name:)
Telephone (212) 840-1070	☒	Modification to NERC Glossary term or addition of new term

Brief Description of Proposed Standard Modifications/Actions (In three sentences or less, summarize the proposed actions a drafting team will be responsible for implementing.) By this Standard the Drafting Team will establish the requirements for capturing power system disturbance data to enable the effective analysis of power system disturbances.
Need (Explain why the Standard is being developed or modified. Clearly indicate why the actions being proposed are needed for maintaining or improving bulk power system reliability, including an assessment of the reliability and market interface impacts. This is similar to the Purpose statement in a Reliability Standard.) PRC-002 is being revised to ensure the capturing of power system data following a system disturbance. (Note that the development of PRC-002-2 under Project 2007-11 was made informal in 2011.) The emphasis will not be on what equipment may be used to capture this data, but on ensuring that the requisite data is captured. PRC-002-2 will also include the pertinent requirements of PRC-018-1 that will allow that Standard to be retired. This will improve system reliability by providing personnel with described data to enable more effective post events analyses. This information will also be used to verify system models.
Goals (Describe what must be accomplished in order to meet the above need. This section would become the Requirements in a Reliability Standard.) Sufficient Sequence of Events, Fault, and Dynamic Disturbance recordings to analyze power system disturbances must be captured and accessible.
Objectives and/or Potential Future Metrics (Describe what the potential measure or criteria for success may be for determining the successful implementation of this request. Provide ideas for potential metrics to be developed and monitored in the future relative to this request, if any.) To obtain adequate power system data to perform an analysis of an event on the BES.
Detailed Description (In three paragraphs or more, provide a detailed description of the proposed actions a drafting team will be responsible for executing so that the team can efficiently implement this request. While you will check applicability boxes on the following page, this description must include proportional identification of to whom the standard should apply among industry participants.) Using the version of PRC-002-2 that had been developed when the Project was categorized as informal in 2011, the Drafting Team will make the revisions necessary to reflect the goal of collecting sufficient Bulk Electric System disturbance data. The revised version will be posted for industry comment, and the Standard revised and reposted as necessary. The Drafting Team will also review technical justifications for requirements in the Standard. The Drafting Team will also be responsible for taking the steps necessary to expose industry to the content of the Standard. This will give industry the opportunity to make more informed comments, and improve the overall process.

In the Applicability Section, responsible entity was used to include the Planning Coordinator and Reliability Coordinator functional entities as described in the NERC Functional Model. The Drafting Team recognized that among the different regions there are different entities that address Dynamic Disturbance recording. The appropriate use of responsible entity will ensure that the responsibility for collecting needed disturbance data will be recognized. For requirements for which neither the Planning Coordinator or the Reliability Coordinator is the appropriate applicable entity, the specific functional entity will be named. The Transmission Owners and Generator Owners will be responsible for the bulk of the Requirements in this Standard. The Planning Coordinators and Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data. The drafting team is creating the following new terms: Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording.
OPTIONAL: Technical Analysis Performed to Support Justification (Provide the results of any technical study or analysis performed to justify this request. Alternatively, if deemed necessary, propose a technical study or analysis that should be performed prior to a related standard development project being initiated in response to this request.) A study of multiple systems across the continent was done to determine the locations needed to record sufficient power system data for Sequence of Events, Faults, and Dynamic Disturbances based on three phase bolted short circuit MVA thresholds.

Reliability Functions

The Standard(s) May Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Entity	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource	Develops a >one year plan for the resource adequacy of its

	Planner	specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard(s) comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
PRC-018-1	This Standard to be retired after PRC-002 approved.
PRC-002-NPCC-01	Redundant requirements to be removed from this Standard.

Related Projects

Project ID and Title	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Authorization Request Form

Title of Proposed Standard:	Disturbance Monitoring (Project 2007-11)
Request Date: Revised Date:	March 1, 2007 May 21, 2007

SAR Requester Information

Name: Robert W. Millard on behalf of the Regional Reliability Standards Working Group		SAR Type (Check one box.)	
Company:	Reliability*First* Corporation	☐	New Standard
Telephone:	(708) 588-9886	☒	Revision to Existing Standard
Fax:	(330) 456-3648	☐	Withdrawal of Existing Standard
E-mail:	bob.millard@rfirst.org	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard – what the standard will achieve in support of reliability.)

~~To establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of disturbance data to facilitate analyses of events and verify system models.~~

~~PRC-002 — Define and Document Disturbance Monitoring Equipment Requirements~~

~~PRC-018 — Disturbance Monitoring Equipment Installation and Data~~

~~PRC-002 was a Version 0 standard that was modified solely to add Phase III & IV Planning Measures; PRC-018 is a new standard developed as a translation of Phase III & IV Planning Measures. As the Electric Reliability Organization begins enforcing compliance with Reliability Standards under Section 215 of the Federal Power Act in the United States and applicable statutes and regulations in Canada and Mexico, the industry needs a set of clear, measurable, and enforceable Reliability Standards. The Version 0 standards and the translation of Phase III & IV Planning Measures, while a good foundation, were translated from historical operating and planning policies and guides that were appropriate in an era of voluntary compliance. The Version 0 standards, Phase III & IV standards, and recent updates were put in place as a temporary starting point to start-up the Electric Reliability Organization and begin enforcement of mandatory standards. However, it is important to update the standards in a timely manner, incorporating improvements to make the standards more suitable for enforcement and to capture prior recommendations that were deferred during the Version 0 and Phase III & IV translations.~~

Industry Need (Provide a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

PRC-002 is being revised to ensure the capturing of power system data following a system disturbance. (Note that the development of PRC-002-2 under Project 2007-11 was made informal in 2011.) The emphasis will not be on what equipment may be used to capture this data, but on ensuring that the requisite data is captured. PRC-002-2 will also include the pertinent requirements of PRC-018-1 that will allow that Standard to be retired. This will improve system reliability by providing personnel with described data to enable more effective post events analyses. This information will also be used to verify system models.

~~1. Provide an adequate level of reliability for the North American bulk power systems — ensure the standards are complete and the requirements are set at an appropriate level to ensure reliability.~~

~~2. Ensure they are enforceable as mandatory reliability standards with financial penalties — ensure~~

~~(a) the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined,~~

~~(b) the purpose, requirements, and measures are results-focused and unambiguous and~~

~~(c) the consequences of violating the requirements are clear.~~

~~3. Consider comments received during the initial development of this set of standards and other comments received from ERO regulatory authorities and stakeholders as described in the Detailed Description section below.~~

~~4. Bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure as described in Attachment 1 below.~~

~~5. Satisfy the standards procedure requirement for five-year review of the standards.~~

Brief Description (Describe the proposed standard in sufficient detail to clearly define the scope in a manner that can be easily understood by others.)

By this Standard the Drafting Team will establish the requirements for capturing power system disturbance data to enable the effective analysis of power system disturbances.

~~PRC-002 and PRC-018 were approved in 2006.~~

~~PRC-002 is one of four reliability standards identified by the Regional Reliability Standards Working Group as a standard that has some requirements that need to be defined by each regional entity in a regional standard. The standard drafting team (SDT) will review PRC-002 and each of the current regional programs developed in accordance with that standard, including any other associated programs and/or requirements related to or contained with the disturbance monitoring program documentation. The SDT shall determine which requirements should be continent-wide requirements and which requirements should be included in regional standards.~~

~~When revising PRC-002 and PRC-018 the SDT will, the SDT shall consider comments and issues as described in the Detailed Description section and Attachment 1 below for drafting and including other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders through the standards development procedure, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.~~

~~Note: Phasor measurement networks are to be addressed by Project 2008-06.~~

Reliability Functions

The Standard will Apply to the Following Functions (Check all applicable boxes.)		
☒ ☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check all boxes that apply.)	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
☒	5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
Recognizing that reliability is an essential requirement of a robust North American economy:
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a standard based on this description.)

Using the version of PRC-002-2 that had been developed when the Project was categorized as informal in 2011, the Drafting Team will make the revisions necessary to reflect the goal of collecting sufficient Bulk Electric System disturbance data. The revised version will be posted for industry comment, and the Standard revised and reposted as necessary. The Drafting Team will also review technical justifications for requirements in the Standard.

The Drafting Team will also be responsible for taking the steps necessary to expose industry to the content of the Standard. This will give industry the opportunity to make more informed comments, and improve the overall process.

In the Applicability Section, responsible entity was used to include the Planning Coordinator and Reliability Coordinator functional entities as described in the NERC Functional Model. The Drafting Team recognized that among the different regions there are different entities that address Dynamic Disturbance recording. The appropriate use of responsible entity will ensure that the responsibility for collecting needed disturbance data will be recognized. For requirements for which neither the Planning Coordinator or the Reliability Coordinator is the appropriate applicable entity, the specific functional entity will be named.

The Transmission Owners and Generator Owners will be responsible for the bulk of the Requirements in this Standard. The Planning Coordinators and Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data.

The drafting team is creating the following new terms: Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording.

~~The SDT shall consider the following comments (excerpted from NERC's Reliability Standards Development Plan: 2007-2009) which attempt to capture comments from the:~~

~~FERC NOPR (Docket # RM06-16-00 dated October 20, 2006),~~

~~FERC staff report dated May 11, 2006 concerning NERC standards submitted with ERO application, and~~

~~Regional Fill-in-the-Blank Team (RRSWG – a NERC working group involved with regional standards development).~~

- ~~Phase III & IV Standard Drafting Team~~
- ~~Violation Risk Factors Drafting Team~~

~~PRC-002 Define and Document Disturbance Monitoring Equipment Requirements~~

~~FERC NOPR~~

- ~~Commission will not propose to accept or remand this Reliability Standard until the ERO submits additional information related to the fill-in-the-blank aspects of this standard as further defined below under "Regional Fill-in-the-Blank Team Comments".~~

~~FERC Staff Report~~

~~• This standard designates RROs as the applicable entity. Staff is concerned about the appropriateness of RROs serving as the applicable entity in the new mandatory standards structure. These standards have been referred to as "fill-in-the-blank" standards (see comments under "Regional Fill-in-the-Blank Team Comments" below).~~

~~Phase III/IV comments~~

~~• There are no criteria that the RROs must use in specifying the process for identifying locations where DMEs are required (to be addressed when considering issues under "Regional Fill-in-the-Blank Team Comments" below).~~

~~Violation Risk Factor Drafting Team Comments~~

~~• R1 - This standard and all related sub requirements are after the fact data analysis.~~

~~Regional Fill-in-the-Blank Team Comments~~

~~• Determine what elements (if any) should be included in the North American standard and what elements should be included in the regional standards.~~

~~• Development of regional standards needs to be coordinated with regional entities.~~

~~• Regional entities should be notified to begin process for developing regional standards once the standard drafting team has determined what elements should be included in the continent-wide standard and what elements should be included in the regional standards.~~

~~PRC-018 Disturbance Monitoring Equipment Installation and Data~~

~~Violation Risk Factor Drafting Team Comments~~

~~• R3.4, 3.5, 3.6, 3.7 Requirements as written are ambiguous and need more clearly defined.~~

~~1. The SDT will bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Rules of Procedure as described in Attachment 1 below.~~

~~2. The SDT should also consider any other issues that were not completely captured but were stated or referenced in the above materials.~~

~~3.~~1. ~~The SDT should consider issues raised by the industry during the posting of the SAR for Project 2007-11 during the first comment period from March 22 through April 20, 2007, attached as Attachment 2.~~

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

~~Attachment 1~~

~~Excerpts from the *Reliability Standards Development Procedure Manual, Version 6* and the *ERO Rules of Procedure*:~~

~~(The drafting team will reference and follow, as appropriate, the following guidelines *(or later version as appropriate)* in determining what changes to make to the standards to bring them into conformance with these guidelines.)~~

~~Standard Review Guidelines~~

~~Applicability~~

~~Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?~~

~~Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.~~

~~Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.~~

~~Purpose~~

~~Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.~~

~~Performance Requirements~~

~~Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?~~

~~Does each requirement identify who shall do what under what conditions and to what outcome?~~

~~Measurability~~

~~Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?~~

~~Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?~~

~~If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?~~

~~Technical Basis in Engineering and Operations~~

~~Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?~~

~~Completeness~~

~~Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?~~

~~Consequences for Noncompliance~~

~~In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?~~

~~Clear Language~~

~~Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?~~

~~Practicality~~

~~Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?~~

~~Capability Requirements versus Performance Requirements~~

~~In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.~~

~~Consistent Terminology~~

~~To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?~~

~~If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.~~

~~Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?~~

~~**Violation Risk Factors (Risk Factor)**~~

~~**High Risk Requirement**~~

~~A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;~~

~~or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.~~

~~**Medium Risk Requirement**~~

~~A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;~~

~~or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.~~

~~**Lower Risk Requirement**~~

~~A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;~~

~~or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.~~

~~**Time Horizon**~~

~~The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:~~

- ~~**Long-term Planning** — a planning horizon of one year or longer.~~
- ~~**Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.~~
- ~~**Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.~~

- ~~**Real-time Operations** – actions required within one hour or less to preserve the reliability of the bulk electric system.~~
- ~~**Operations Assessment** – follow-up evaluations and reporting of real time operations.~~

~~**Violation Severity Levels**~~

~~The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.~~

~~**The violation severity levels should be based on the following definitions:**~~

- ~~**Lower: mostly compliant with minor exceptions** – The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.~~
- ~~**Moderate: mostly compliant with significant exceptions** – The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.~~
- ~~**High: marginal performance or results** – The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.~~
- ~~**Severe: poor performance or results** – The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.~~

~~**Compliance Monitor**~~

~~Replace, 'Regional Reliability Organization' with 'Regional Entity'~~

~~**Fill-in-the-blank Requirements**~~

~~Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.~~

~~Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.~~

~~**Requirements for Regional Reliability Organization**~~

~~Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.~~

~~**Effective Dates**~~

~~Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply.~~

~~If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.~~

~~Associated Documents~~

~~If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.~~

~~Functional Model Version 3~~

~~Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.~~

~~Attachment 2~~

~~Issues Raised by Industry During 1st Posting of SAR for Project 2007-11 Which are Outside the Responsibility of the SAR Drafting Team~~

~~Question 4 of the Comment Form:~~ *~~Please provide any other comments (that you have not already provided in response to the first three questions on this form) that you have on the revised SAR.~~*

~~IRC Standards Review Committee commented:~~
~~The SDT should pose questions regarding:~~
~~(1a) whether or not NERC should require data recording performance requirements that can only be met by purchasing specific assets~~

~~(1b) If it is sufficient to mandate what information and performance is required rather than the hardware itself (it should accomplish the same results but would avoid the issue of asset purchasing)~~

~~(1c) Should assets per se be handled by the certification / recertification process – if the entity does not have the equipment, then it can not be certified; and if it doesn't continue to meet the requirements, it would not be able to meet compliance objectives~~

~~(2) If the PRC-002 requirements were not interconnection-wide, then DT should ask whether or not the obligation for the DME characteristic plans be assigned to the PC or TOP rather than the Regional Entity? PCs and TOPs have a better understanding of their own locality than would a region that may be tempted to homogenize the characteristic requirements~~

~~(3) Should ad hoc hardware details (sampling rates, file naming; format) be left to NAESB rather than NERC? Reliability only needs the information – efficiency and commonality would seem to be more related to Business Practices.~~

Unofficial Comment Form

Project 2007-11 Disturbance Monitoring

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard Authorization Request (SAR). The electronic comment form must be completed by **Monday, June 3, 2013**.

If you have questions please contact Barb Nutter at barbara.nutter@nerc.net or by telephone at 404.446.9692.

2007-11 Disturbance Monitoring Project Page

Background Information
This posting is soliciting informal comment.

Project 2007-11 Disturbance Monitoring was initiated to address an existing "fill in the blank" standard. FERC did not approve or remand PRC-002-1 in Order 693 because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. FERC did approve PRC-018-1 in Order 693. Similar to PRC-002-1, PRC-018-1 contained Regional Reliability Organization requirements, but FERC stated that the requirements are clear enough to be enforced.

The purpose of this revised SAR is to establish requirements for recording and reporting sequence of events (SOE) data, fault recording (FR) data, and dynamic disturbance recording (DDR) data to facilitate analyses of Disturbances.

This Project will replace PRC-002-1 and PRC-018-1 with PRC-002-2.

PRC-002-1 is being revised to ensure the capturing of power system data following a system disturbance. (Note that the development of PRC-002-2 under Project 2007-11 was made informal in 2011.) The proposed standard will not specify what equipment must be used to capture this data, but on ensuring that the requisite data is captured. This will improve system reliability by providing personnel with necessary data to enable more effective analysis of events that affect the Bulk Electric System. This information will also be used to verify system models. PRC-002-2 will also incorporate the pertinent requirements of PRC-018-1 so that PRC-018-1 may be retired.

Using the version of PRC-002-2 that was developed when the Project was in informal development, the Drafting Team will make the revisions necessary to reflect the goal of collecting sufficient Bulk Electric System disturbance data. The Drafting Team will also review technical justifications for requirements in the Standard.

The Drafting Team will also take the steps necessary to present to industry to the content of the Standard. This will give industry the opportunity to make more informed comments, and improve the overall process.

In the Applicability Section, Responsible Entity was used to include the Planning Coordinator and Reliability Coordinator functional entities as described in the NERC Functional Model. The Drafting Team recognized that among the different regions there are different entities that address Dynamic Disturbance recording. The appropriate use of Responsible Entity will ensure that the responsibility for collecting needed disturbance data will be recognized. For requirements for which neither the Planning Coordinator or the Reliability Coordinator is the appropriate applicable entity, the specific functional entity will be named.

The Transmission Owners and Generator Owners will be responsible for the bulk of the Requirements in this Standard. Planning Coordinators and Reliability Coordinators as applicable will be responsible for determining a list of locations for which the owner must capture Dynamic Disturbance data.

A study of multiple systems across the continent was done to determine the locations needed to record sufficient power system data for Sequence of Events, Faults, and Dynamic Disturbances based on three phase bolted short circuit MVA thresholds.

The drafting team is creating the following new terms: Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording. The drafting team is also using the NPCC Regional definition of Generating Plant in PRC-002-2, and is proposing to move the Regional definition to the NERC Glossary.

You do not have to answer all questions. Enter All Comments in Simple Text Format.
Bullets, numbers, and special formatting will not be retained. Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree the scope of the revised SAR describes the work to be performed in this project? If not, please explain.

☐ Yes
☐ No
Comments:

2. The revised SAR identifies a list of functional entities that may be assigned responsibility for requirements in the set of standards addressed by this SAR. Do you agree with the list of proposed applicable functional entities? If no, please explain.

☐ Yes
☐ No
Comments:

3. Do you agree there is a need for a standard? Please explain your response.

☐ Yes
☐ No
Comments:

4. If you do not believe a standard is needed - what other method could be used to achieve the results stated in the revised SAR.

☐ Yes
☐ No
Comments:

5. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:
Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement Updated Links

Project 2007-11 Disturbance Monitoring

Revised SAR Informal Comment Period Open: May 3, 2013 – June 3, 2013

Now Available

A revised Standard Authorization Request (SAR) for Project 2007-11 Disturbance Monitoring is posted for a 30-day informal comment period through **8 p.m. Eastern on Monday, June 3, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

The comment period for the revised SAR is open through **8 p.m. Eastern on Monday, June 3, 2013**. Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The drafting team will consider all comments received during the informal comment period and determine if revisions to the current standards are necessary. The drafting team will then make a recommendation to the Standards Committee on whether or not to proceed with the project.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (44 Responses)
Name (26 Responses)
Organization (26 Responses)
Group Name (18 Responses)
Lead Contact (18 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)
Comments (44 Responses)
Question 1 (42 Responses)
Question 1 Comments (43 Responses)
Question 2 (38 Responses)
Question 2 Comments (43 Responses)
Question 3 (41 Responses)
Question 3 Comments (43 Responses)
Question 4 (13 Responses)
Question 4 Comments (43 Responses)
Question 5 (0 Responses)
Question 5 Comments (43 Responses)

Group
test
test
Agree
Group
Northeast Power Coordinating Council
Guy Zito
No
There is no specific mention of the removal of the PRC-018 R6 Maintenance requirement in the SAR. The original SDT was moving it to PRC-005. R6 is ambiguous, and if included needs to be revised or else should be removed. It should be stipulated that DFR/DDR should be verified semi-annually to ensure that the device is receiving analog signals. The Need Section should be revised to limit the applicability to the BES, and to exclude the verification of system models as a specific need for this standard. Suggest the following wording for the Need Section: PRC-002 is being revised to ensure adequate BES data is captured to enable effective post event analysis following a BES disturbance. (Note that the development of PRC-002-2 under Project 2007-11 was made informal in 2011.) The emphasis will not be on what equipment may be used to capture this data, but on ensuring that the requisite data is captured. PRC-002-2 will also include the pertinent requirements of PRC-018-1 that will allow that Standard to be retired. Utilization of this data will allow the entity to improve system reliability through BES system improvement. The wording under Brief Description of Proposed Standard Modifications/Actions should also be revised to the following for consistency: By this Standard the Drafting Team will establish the requirements for capturing BES disturbance data to enable effective post event analysis following a BES disturbance. The Standard Drafting Team (SDT)

will review PRC-002 and any NERC approved Regional Disturbance Monitoring Standard.
Yes
No
Once the Standard becomes effective, it will provide continent-wide consistency and clarity for capturing the data needed to analyze various power system disturbances, and validate some of the models used in planning or operational studies. It will decrease the number of standards for this topic.We don’t agree with the need for a standard as proposed. There could be a general requirement for providing DME data for events analysis and modeling purposes that could be put in the Rules of Procedure as opposed to a standard.
Yes
We are in favor of having disturbance monitoring equipment (DM) data capture with common capabilities in the field, but we have concerns with the SAR’s approach. There could be a general requirement for providing DME data for events analysis and modeling purposes that could be put in the Rules of Procedure as opposed to a standard. We would recommend that the NERC Planning Committee develop a common specification and approach to be used for all North America. If the goal of PRC-002 is to enable a data stream for modeling and disturbance analysis, there should be a single standard for provision of such data or a provision included in the Rules of Procedure.
A thoughtful approach must be considered to the possibility of fill-in-the-blank requirements in the standards that apply to the Regional Reliability Organization. Many of these things are no longer done and should be removed from the standards. Some are procedural processes that need not be in the standards, but rather enforced through regional agreements. A few of the items should be codified in the Rules of Procedure. Three phase bolted short circuit MVA thresholds don't appear as appropriate criteria to determine the locations needed to record sufficient power system data for Dynamic Disturbances as stated in SAR (Technical Analysis Performed to Support Justification). Instead of three phase short circuit thresholds, the Planning Coordinator (PC) / Reliability Coordinator (RC) should consider other criteria such as large generation stations with a combined capability above a certain MW level, major load centers, regional and interregional transmission interfaces (flow gates), substations with large tap-changing and phase-shifting transformers, key substations in major load centers. Only Principle number 7 applies. The proposed standard purpose is to collect information to facilitate analysis of a BES disturbance. DDR/DFR do not control, operate, or monitor the BES system. Compliance to this Standard may require Owners to install new equipment. The Implementation Plan when developed should consider the need to budget, engineer, procure and install new DME. Referring to the fourth paragraph of the Detailed Description, it is not appropriate to assign the responsibility of the functional entities. Recommend the fourth paragraph be changed as follows: It is envisioned that the Transmission Owners and Generator Owners will be responsible for the bulk of the Requirements in this Standard and that the Planning Coordinators or Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data. A sentence should be added in the "Need" section to indicate that the Standard Drafting Team will review the need for having a regional Disturbance

Monitoring standard (PRC-002-NPCC-01). The location where disturbance monitoring devices will be required must be clearly identified by the SDT using clear equipment description (generating station, unit, bus, lines, transformers…) and clear MVA and/or kV thresholds. In reference to the fourth paragraph of the "Detailed Description" section, consideration should be taken in scenarios where the physical location of the disturbance monitoring equipment is shared between the Generator Operator and the Transmission Operator. Addressing this scenario would prevent duplication of equipment at nearby locations or at the same location.
Group
Operational Compliance
Ed Croft
Yes
Yes
Yes
Individual
Michael Moltane
ITC
Yes
The post 2003 blackout recommendations included the need for synchronized recording devices in power plants and substations to aid in the analysis of wide area events. The industry is faced with a conflict where PRC-002-1 is a fill in the blank standard, thus not FERC approved, but PRC-018-1 is FERC approved. Combining PRC-018-1 into the new PRC-002-2 which will be a continent wide standard is the only way to correct this issue.
Individual
Michael Falvo
Independent Electricity System Operator
Yes

Yes
Yes
Once the standard becomes effective, it will provide similar continent wide conditions for capturing data needed in analyzing various power system disturbances and validating some of the models used in planning or operational studies.
Yes
We advise the SDT to be mindful of the varied system characteristics among different regions and areas. Hence, the standards should not stipulate a one-size fit all type of installation requirements – may that be locational, geographical or voltage based. The locations for installing DMEs, especially the dynamic disturbance recorders, need to consider the relevance, value and type of the recorded data that can contribute to accomplishing the purpose of having useful information for event analysis.
Group
Pepco Holdings Inc. & Affiliates
David Thorne
Yes
Yes
Yes
When determining the selection criteria for where this equipment is to be located, the SDT should be mindful of the significant dollars and resources already expended over the last several years to add DME equipment to specific sites specified by the Regional Reliability Organizations in accordance with PRC-002.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes
No
We are of the opinion that Transmission Owners are the primary applicable entities, with Generator Owner applicability being limited to specific cases (see #5 below). The Transmission Operator and Generator Operator should be removed from applicability to this standard.

Yes
The requirement for generator Dynamic Disturbance Recording (DDR) should be reserved for areas having critical density of generation or load, or for generation near critical flowgates, or for other areas which are recognized as having potential generator stability issues. It should not simply be applied to all generators above a given size. Also for generators, the requirement for DDR should be able to be sufficiently satisfied by using data from plant Distributed Control Systems (DCS).
Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst agrees that the scope of the revised SAR adequately describes the necessary work to be performed in this project. ReliabilityFirst agrees that the shift in focus of the SAR to ensure that the requisite disturbance data is captured (rather than prescribing the equipment which must be used to capture disturbance data) is an appropriate course of action.
Yes
ReliabilityFirst believes there is definitely a need for this standard. ReliabilityFirst offers the following reasons in support of this standard’s development. This proposed standard will improve system reliability by providing personnel with necessary data to enable the industry to more effectively analyze system events that affect the Bulk Electric System and Bulk Power System. The new version of the standard will remove the "fill-in-the-blank" requirements currently assigned to the Regional Reliability Organization within the current PRC-018-1 and PRC-002-1 standards. And finally, with the events data system models can be reviewed and verified for better accuracy. Each of which will enhance overall system reliability.
Individual
Gustavo Brunello
Gustavo Brunello
Yes
Yes
Yes

Yes
what is the difference between "Disturbance" and "Event" in the following 2 clauses: R13. Each Transmission Owner and Generator Owner shall have all recorded Sequence of Event, Fault Recording, and DDR data available (locally or remotely) for 10 calendar days after a Disturbance D_Compliance_ 1.3.1 Each Transmission Owner and Generator Owner shall retain all data provided to the Regional Entity, Reliability Coordinator or NERC for at least three years following the event.
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
(1) General - de-capitalize the word “standard” throughout the SAR. Alternatively, replace the word “standard” with the words “Reliability Standard”. (2) Need - add a “-“ between the words bulk power for consistency with other instances of these words. (3) Objectives and/or Potential Future Metrics - rewrite “BES” as Bulk Electric System (BES) because it is the first instance of these words in the SAR. Also, for clarity, consider adding the words “North American” before Bulk Electric System. (4) Detailed Description - replace Bulk Electric System with its acronym “BES”. (5) General - de-capitalize all instances of “Requirements” because it is not defined in the NERC Glossary of Terms. (6) Detailed Description - capitalize the words “drafting team” in the last paragraph in this section for consistency with the rest of the document. (7) OPTIONAL: Technical Analysis Performed to Support Justification - for clarity, “continent” should be referred to as “North American continent”.
Individual
Wryan Feil
Northeast Utilities
No
We propose that the “Need Statement” be revised for the following two reasons: a. to limit the applicability to the BES, b. to exclude the verification of system models as a specific need for this standard We propose the following wording be considered: “PRC-002 is being revised to ensure adequate BES data is captured to enable effective post event analysis following a BES disturbance. (Note that the development of PRC-002-2 under Project 2007-11 was made informal in 2011.) The emphasis will not be on what equipment may be used to capture this

data, but on ensuring that the requisite data is captured. PRC-002-2 will also include the pertinent requirements of PRC-018-1 that will allow that Standard to be retired. Utilization of this data will allow the entity to improve system reliability through BES system improvement." And the wording under Brief Description should also be changed to the following for consistency: "By this Standard the Drafting Team will establish the requirements for capturing BES disturbance data to enable effective post event analysis following a BES disturbance. The standard drafting team (SDT) will review PRC-002 and any NERC approved Regional Standard PRC-002." Under Goals we recommend the following wording: "Sufficient Adequate (limited redundancy) Sequence of Events, Fault, and Dynamic Disturbance recordings to analyze power system disturbances must be captured and accessible." Where means Adequate means: (lawfully and reasonably sufficient) Sufficient means: (enough to meet the needs of a situation or condition)
Yes
Yes
Yes
We think it is not appropriate to assign under the Detailed Description the responsibility of the functional entities. We recommend the fourth paragraph be changed as follows: "It is envisioned that the Transmission Owners and Generator Owners will be responsible for the bulk of the Requirements in this Standard and that the Planning Coordinators or Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data."
Group
Tri-State Generation & Transmission
Bill Middaugh
Yes
No
We believe that the drafting team should develop requirements for specifying which locations require Dynamic Disturbance data. That would eliminate the need for including the Planning Coordinator and the Reliability Coordinator. If a coordinating entity is retained in the Applicability, it should only be the Planning Coordinator because the Functional Model does not provide for assigning this type responsibility to the Reliability Coordinator.
Yes
No other comments.
Individual

Don Schmit
Nebraska Public Power District
No
Focusing on data rather than equipment to provide the required recorded information has benefits however this creates some concerns. For example, assume we have a GPS clock and relay that can meet the 2ms criteria however prior to an event the clock loses time due to an internal error (these devices are not perfect) so the relay no longer has the correct time of the event. If this data is then requested by the RE would this be a compliance violation because the data is wrong even though the equipment is capable of meeting the criteria? Will this data be audited? Even though the focus is on data and equipment capabilities and not specifying stand alone or relaying equipment to record data it seems there should be some discussion on the maintenance differences. I recommend that protective relays used for DME type functions should not be in two maintenance plans.
No
In the past there was desire to have a continent wide standards that did not vary based on regions so the requirements were uniform across the continent. Is it now the goal to accept differences in the requirements by regions? Perhaps clarify if this uniformity is not desired.
Yes
I have concerns that at stations that have recording equipment already in place that they may not meet the data capabilities required. This may be a significant # of locations for some TOs. Will there be a way to grandfather in existing locations that will be specified in the standard? Some of the statements from the webinar were to use the fault study and then select 20% of buses using the MVA criteria. This kind of analysis seems straight forward but can create complexity with how it is audited by enforcement in order to prove that 20% was achieved. In general does the drafting team consider how the standard may be audited? Some aspects of the standard may be difficult to audit so one recommendation is to try and consider if there will be difficulties with auditing as requirements are written. I think that if protective relays are acceptable for performing certain DME functions at certain locations they should not have a maintenance requirement under PRC-002 if they are maintained under PRC-005. The SDT may already agree with this but if not please take this under consideration. PRC-005 is a stringent standard that already aims to make sure relaying is operable for protection which is more critical to the BES then data recording in comparison and it has much longer intervals than quarterly. Many relays could meet the 50 cycles recording length but they are not perfect devices. If a relay does not capture at least 2 cycles of pre trigger and 50 cycles of a fault lasting longer than 50 cycles is this a compliance violation? This requirement is logical but I have concern about compliance and overwriting relay data with extending record length. The need for monitoring tie lines needs to be clear. From the webinar it may not have been.
Individual

John Bee
Exeln and its affiliates
Yes
ComEd believes that fault recording equipment and dynamic disturbance recording equipment that is time synchronized by a GPS Satellite clock are sufficient to analyze disturbances. Although separate sequence of event recording may be useful for Generator Owners/Operators, it should not be required for Transmission Owners. Modern microprocessor relays already include a great deal of built-in sequence of event recording capability. A requirement for SOE capability is thus not needed in a standard and would only be burdensome. Additionally, experience at Exelon has shown that investigation of power system events very rarely requires the use of this built-in sequence of event records capability to determine the root cause of an event.
No
ComEd does not believe that it is necessary that a disturbance monitoring standard apply to the planning coordinator or reliability coordinator. ComEd is rapidly installing modern protection equipment such that eventually all HV & EHV transmission lines and transformers will be protected by equipment with built-in oscillographic and sequence of events capabilities. By the end of 2015, with or without a standard, all of ComEd's EHV lines will have built-in oscillographic and sequence of events capabilities. Currently, the majority of both HV and EHV line relaying are microprocessor based. Thus, there is no need for any involvement of the planning coordinator or reliability coordinator to determine requirements or locations for oscillographic or sequence of events capabilities. For long term disturbance monitors, ComEd believes the standard would be better served by providing a short list of important circuits that would require stored synchrophasor data or long term disturbance monitoring, i.e. all generators greater than X MW or at the tie point of generating stations greater than Y MW aggregate capacity, stability limited lines or IROLS, etc. This would eliminate the need for involving the planning coordinator or reliability coordinator and target required recording data to the most important circuits only. Also, the minimum amount of useful data should be required to be stored for long term disturbance monitors (positive sequence voltage and current (or one phase of voltage and current) and frequency). MW and MVAR can always be calculated. Including the Reliability Coordinator and/or Planning Coordinator is like creating a fill in the blank standard just with a different entity filling in the blank.
Yes
Yes, however, this standard should be very low burden as a good argument could also be made that a standard is not needed at all. Since the 2003 Blackout, the proliferation of microprocessor relays with ever increasing oscillographic recording and sequence of event recording capabilities has increased the amount of data available to a high level and this increase will continue over time with or without a standard. Many entities, including ComEd, include GPS Satellite clocks in the standard design of their transmission relay schemes, etc. Many entities are voluntarily installing equipment that records and stores synchrophasor data on important generator connections and circuits. This is evidenced by comments by NERC

related to investigations of more recent disturbances versus disturbances in the past. We recommend that the only things that need to be in a standard for disturbance monitoring equipment is that a simple list of fault recording equipment needs to be kept, whatever type is used (i.e. relay type (e.g. SEL321), DFR type). Also, a list of long term disturbance monitoring equipment needs to be kept, whatever type is used (long term disturbance monitors or stored phasor data) including that the equipment is connected to a GPS Satellite clocks. Additionally, the standard could require continuous recording for any long term disturbance monitoring, although this is already industry standard, with data retention at least a certain time (e.g. 10 days) and connection of all new monitoring equipment to a GPS Satellite clock. Anything else is just a significant record keeping burden that ComEd does not believe adds anything to reliability and therefore is not justifiable. With modern equipment it is not necessary for NERC to specify things like sample rates, tolerance/accuracy of GPS clocks, etc.
The Exelon business units have been using the RFC criteria PRC-002 and have spent time and money to implement the methodology for capturing and reporting data to align with the RFC criteria. The concern is that there are intentions to move away from the Regional Criteria which would cause a reevaluation and possible rework to the methodology currently used.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Yes
The standard is needed in order to ensure that sufficient information is collected during a system disturbance to properly evaluate and simulate the disturbance.
Group
MRO NERC Standards Review Forum
Joseph DePoorter
Yes
Although the NSRF agrees with capturing BES event data, there are entities who currently have devices installed which gather DME data. The issue is how can a Standard (such as PRC-002) mandate the purchasing of such equipment? The cost could be substantial for both large and small applicable entities.
Yes

No
Yes
The cost associated with a 20% bus implementation could be great for both large and small entities (even though the NSRF believes this is being discussed within the SDT). Perhaps NERC should capture what is currently installed within each interconnection as a starting point prior to new installs or relocation of current devices. The Standard should have a foot note (as in PRC-024-1, foot note 1) that states applicable entities are not required to have DME installed or activated on their assets, or words to that effect. This will allow applicable entities to follow the direction of their RC or PC in where they should place DMEs. It will also allow applicable entities understand the importance of installing DMEs and allow the future budgeting of DME's.
Group
PacifiCorp
Ryan Millard
Yes
Yes
Yes
No
Group
North American Generator Forum Standards Review Team
Patrick Brown
Yes
Yes
The SRT believes it may be necessary to add the Distribution Provider depending on what requirements are eventually developed.
Yes
Previously proposed Disturbance Monitoring standards were often vague on who was responsible for requirements and it was difficult for entities to determine exactly the scope of

the standard. We see the benefit of this project and encourage the standard drafting team to avoid repeating the mistakes of the past.
1. The PRC-002/018 SDT should keep cost justification in mind, especially as regards TO-vs-GO duplication of DME. This project should be included in the CEAP Pilot Program. 2. We have been installing this equipment in accordance with our RRO's requirements, but it seems unlikely that anyone will ever ask for data, since the TO has DME on their side of the fence at each plant. The role of GO-collected data in Disturbance analysis may be minimal to nonexistent, in which case it would make sense to require GO's to have DME only under very limited circumstances. 3.The revised PRC-002/018 standard should also define the target settings required. The NERC Glossary definition of a Disturbance is of no use, and the criteria in Att. 2 of EOP-004 are written solely for the use of TOs.
Individual
Jonathan Meyer
Idaho Power Company
Yes
Yes
Yes
Consistent requirements should assist and facilitate entities with post fault analysis for wide area disturbances and monitoring practices.
Individual
Keith Morisette
Tacoma Power
No
Under the Detailed Description section, it is noted that "the Planning Coordinators and Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data." However, under the Technical Analysis Performed to Support Justification section, it is noted that "a study of multiple systems across the continent was done to determine the locations needed to record sufficient power system data for Sequence of Events, Faults, and Dynamic Disturbances based on three phase bolted short circuit MVA thresholds." These two statements appear to be contradictory. In one case, Planning Coordinators and Reliability Coordinators are to specify locations. In the other case, it can be inferred that sufficient research has been conducted already to propose criteria for specifying locations that would be applicable to the standard. If Planning Coordinators and Reliability Coordinators will

be responsible to specify locations, there should be clear division of authority between these two functional entities. Furthermore, there should be some responsibility for Planning Coordinators and Reliability Coordinators to justify on a technical and financial basis the locations that they specify since Generator Owners and Transmission Owners will bear the direct cost of any new infrastructure to comply with the standard.
No
It is not clear what direct role Generator Operators and Transmission Operators would have in the implementation of PRC-002-2. Furthermore, the other functional entities (Reliability Coordinator, Planning Coordinator, Transmission Owner, and Generator Owner) are mentioned elsewhere in the SAR form while Transmission Operator and Generator Operator are not.
Tacoma Power appreciates this opportunity to provide comments.
Individual
David Jendras
Ameren
No
(1)The slides from the May 22nd NERC webinar indicate considerable PRC-002-2 draft 1 development has already occurred. Based on our experience this draft appears to require a density of disturbance monitoring well in excess of what we believe is needed for disturbance analysis. The SDT has explained the difficulties of developing the August 2003 Blackout sequence of events. (a) Have NERC and its various entities experienced the same level of difficulty in determining a sequence of events since PRC-018-1 and regional criteria have been implemented? (b) For our understanding how many disturbances have NERC and Regional Entities analyzed since June 18th, 2007? (2) Based on our experience we believe that there is now sufficient information to determine the sequence of events, and that regional and NERC disturbance analyses are infrequent. Thankfully widespread disturbances are rare. We understand the importance of disturbance analysis and support an appropriate amount of the correct monitoring equipment, in the right locations, to capture what is necessary to determine sequence of events and system response to determine root cause. (3) We believe that the 1500MVA threshold is very low, too close to current load levels. If 1500MVA is retained, then 20% is too high. (4) We agree that short circuit MVA is a valid factor to consider, however, we also believe that topology is just as important to yield proper placement of disturbance monitors. (5) We request that if <200kV locations are to be included then a bifurcated criteria is warranted and should be used. Major generating sources should be captured, and a much lower percentage of buses are required below 200kV.
Yes
Yes
(1) The SERC Regional Criteria has worked well for SERC and its members. Please consider it as

input to your PRC-002-2 development. Each region’s present criteria are valid input to the standard. As you are aware the BES topology varies considerably depending on load density, so regional variance and even intra-region differences should be considered.
(1) At present, our Planning Coordinator (MISO) is nearing completion on a 3-year project to install Phasor Measurement Units (PMUs) across the MISO controlled transmission system. These PMUs fall into the category of Dynamic Disturbance Recording (DDR) equipment. It is expected across the industry that this type of equipment will be useful in determining the details of system disturbances. (2) According to the Detailed Description of the SAR, on page 3, “The Planning Coordinators and Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data.” We request clarification on how the Planning Coordinator and Reliability Coordinator will be able to fulfill their obligations of locating this monitoring equipment. (3) In addition, we have concerns that revisions to PRC-002, depending on the specifics of the requirements, could be burdensome to Transmission and Generator Owners who may find they have a vastly increased deployment of this type monitoring equipment in order to be compliant.
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration (“ICLP”) agrees that the DME standard should focus on the data desired, not the equipment type. The technology is changing rapidly and PRC-002-2 should not inhibit the use of the latest recorder capabilities.
No
ICLP is not sure what role Planning Coordinators and Reliability Coordinators will play in the updated standard. We believe some caution is in order if the intent is to identify additional locations where DME should be deployed beyond those established through the application of PRC-002-2’s criteria. Since the RC and PC decisions will have a cost impact on a Generator Owner, it is important that limits to their authority are established up front – with an allowance for an appeal to NERC if a dispute arises.
Yes
ICLP sees this project as an opportunity to correct Issues with PRC-018-1 which we believe serves no reliability purpose. In particular, the existing requirements to perform regular DME maintenance are unnecessarily burdensome – as data recorders are not directly tied to BES real time reliability. We have no problem performing the maintenance, but the record keeping – and the zero compliance approach in the intervals is excessive for a data gathering function.
Individual
Thomas Foltz

American Electric Power
Yes
No
AEP agrees overall with the functional entities as specified, however it might be necessary to also include Distribution Provider, depending on what specific requirements are eventually developed.
Yes
The proposed standards developed in earlier phases of this project were often vague on stating specifically who was responsible for the requirements. In addition, it was often difficult for entities to determine which devices were in or out of scope. AEP supports the work of this project team, and would encourage them to avoid those earlier missteps as they develop and propose future revisions.
Group
Dominion
Mike Garton
No
Dominion believes the scope needs to be more clearly defined to ensure the capturing and analysis of disturbances on the “Bulk Electric System” as opposed to the nebulous “power system.”
Yes
No
Yes
Dominion believes the NERC Rules of Procedure can be amended to facilitate analysis of disturbances.
Group
Tennessee Valley Authority
Brandy Spraker
Yes
Yes

Yes
You cannot manage what you do not measure. Much of the data required by this SAR will give utilities better insight into their BES areas.
The determination method might be more suitable if it used the FERC 754 data request bus determination method. The FERC 754 method identifies the more strategic elements in the BES.
Individual
Bill Fowler
City of Tallahassee
Yes
No
TAL believes the same goal could be accomplished by voluntary efforts.
No
TAL believes voluntary efforts on the part of each entity could be used to provide disturbance monitoring, or an alternative is to leave it up to each region to decide what is needed.
no comment
Individual
Karen Webb
City of Tallahassee
Yes
No
TAL believes the same goal could be accomplished by voluntary efforts.
No
TAL believes voluntary efforts on the part of each entity could be used to provide disturbance monitoring, or an alternative is to leave it up to each region to decide what is needed.
Group
Western Area Power Administration
Lloyd A. Linke

No
Including the statement that “This information will also be used to verify system models” goes beyond the purpose of ensuring that the requisite data is captured. Adding requirements for verifying system models will likely over-complicate the standard and delay its ultimate industry approval.
Yes
Yes
Group
FirstEnergy
Larry Raczkowski
Yes
FirstEnergy (FE) prefers this scope for this SAR as opposed to a more prescriptive method of previous standard, ie, this standard will not specify what equipment must be used to capture this data.
No
On page 4 of the SAR, Transmission Operator and Generation Operator are included. FE believes that the respective Owner (Transmission and Generation) should be applicable, not the Operator. FE agrees that the applicable entities are the Transmission Owner, Generation Owner, Planning Coordinator and Reliability Coordinator.
Yes
FE supports NERC's project to develop a continent-wide standard for disturbance monitoring equipment (DME). Installations of DME devices provide valuable insight for post-event analysis and diagnostics. The DME standard must allow for efficient use of equipment sharing for a TO/GO interface location and not force each owner to separately maintain its own equipment. Additionally, an appropriate balance of required locations must be considered in the reliability cost-benefit.
FE is wondering why the reference to a Regional standard is being implied as a related standard in the development of a NERC standard? It is our understanding that the team will begin its work from the draft PRC-002-2 that was started during an informal project development stage. While products from Regional Entity organizations (NPCC, RFC, etc) may be useful for the team's reference, this NERC drafting team should not be editing/revising a Regional Entity standard. We suggest the SAR reference to "PRC-002-NPCC-01... Redundant requirements to be removed from this Standard" as found on the top of page 6 be deleted from the SAR. Additionally the "Related Standards" table should be further edited to insert a row for PRC-

002-1 with an explanation of "Revise to create PRC-002-2" and edit the explanation statement on PRC-018-1 to say "..after PRC-002-2 approved" for version clarity.
Individual
John Seelke
Public Service Enterprise Group
No
The standard produced needs to clarify what events qualify as those for which registered entities are responsible to acquire, save and report SOE, FR and DDR data per the standard. The standard should clarify these events with reference to criteria already established and followed by NERC and/or others such as Regions or ISOs etc in their analysis programs/practices. For example, regarding data for NERC the standard could set out which of the Categories defined in NERC Events Analysis program the data would be required for. At the end of the day no entity wants or should be surprised with a request for data from any entity after any event. And requests for data via this standard need to be reasonable and justifiable by, for instance, the size and/or impact of the event.
Yes
Yes
The need for this standard is driven by recommendations 12A and 12B in the NERC and US-Canada reports on the August 2003 Blackout. The recommendations were made with and in the context of the SOE record produced for and included in the reports. The standard produced via this SAR must improve but be limited to the ability to produce SOE records like those provided in the NERC and US-Canada reports. The standard must be careful not to overshoot with, for instance, requirements designed to acquire data beyond that needed to do SOE records to the extent and granularity included in the NERC and US-Canada blackout reports, which will happen if the standard requires too much data from too many sources (e.g. extensive and unnecessary SOE or FR from small generators or switching stations.
Individual
Chantal Mazza
Hydro Québec TransÉnergie
Yes
Yes
Yes
Hydro-Québec TransÉnergie supports this initiative as it will bring clarity and consistency in the

industry regarding disturbance monitoring while decreasing the number of standards on this topic.
A sentence should be added in the "Need" section to indicate that the Standard Drafting Team will review the need for having a regional Disturbance Monitoring standard (PRC-002-NPCC-01). The location where disturbance monitoring devices will be required must be clearly identified by the SDT using clear equipment description (generating station, unit, bus, lines, transformers…) and clear MVA and/or kV thresholds. In reference to the fourth paragraph of the "Detailed Description" section, consideration should be taken in scenarios where the physical location of the disturbance monitoring equipment is shared between the Generator Operator and the Transmission Operator. Addressing this scenario would prevent duplication of equipment at nearby locations or at the same location.
Individual
Andrew Z. Pusztai
american Transmission Company, LLC
Yes
Yes
Yes
ATC believes the standard is necessary to insure consistency of data across the North American Grid.
ATC supports the objective to not specify the required technology.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
No
Disturbance Monitoring Equipment (DME) should be required of GOs/GOPs only if the TO determines that this equipment is necessary. Generally, GO/GOPs generally have little or no role in analyzing Disturbances. It may be necessary to add Distribution Providers to the list of Responsible Entities depending on what requirements are eventually developed
Yes
Previously proposed Disturbance Monitoring standards were often vague on who was responsible for requirements, and it was difficult for entities to determine exactly the scope of the standard. We see the benefit of this project and encourage the standard drafting team to

avoid repeating the mistakes of the past.
1. The PRC-002-1/PRC-018 SDT should keep cost justification in mind, especially as regards TO-vs-GO duplication of DME. We have been installing this equipment in accordance with our RRO's requirements. However, based on our experience, because TOs have DME on their side of the fence at each plant, the role of GO-collected data in Disturbance analysis may be minimal to nonexistent. Therefore, GOs should be required to have DME only if the applicable TO determines GO DME is necessary. 2. This standard may prove difficult for GOs to comply with in terms of disturbance data retrieval because it is dependent upon being aware that a disturbance is occurring somewhere on the transmission system. The GO is not the primary responsible entity for detecting and reporting a disturbance on the BES. On occasion, there may be information about a disturbance that is available to a TO and may not be available to the GO/GOP, therefore, the GO/GOP should not held accountable for the analysis of the disturbance. It should be clear in the standard that the GO/GOP is accountable only for information that is available to them at the time of the disturbance. The revised PRC-002-1/PRC-018-1 standard should also define the target settings for DME.
Group
Duke Energy
Michael Lowman
Yes
However, we don't believe that this work necessarily must be accomplished in a reliability standard, but could instead be accomplished under the authority of NERC's Rules of Procedure for data collection and Events Analysis Program. See our responses to questions 3 and 4 below.
Yes
However, the Transmission Planner and the Transmission Operator should also be included to work in conjunction with the Reliability Coordinator and the Planning Coordinator to identify locations for collecting Dynamic Disturbance Data.
No
The Standard Drafting Team should consider that, as an alternative to a reliability standard, these provisions for collecting and providing data could be made in NERC's Rules of Procedure. As the Commission recognized in Order No. 693 paragraph 1550 approving PRC-018-1, "the procedures specified in PRC-002-1 will be provided pursuant to the data gathering provisions of the ERO's Rules of Procedure and the Commission's ability to obtain information pursuant to section 215 of the FPA and Part 39 of the Commission's regulations". There is precedent for handling this type of data collection activity in the Rules of Procedure. Reliability standards TPL-005-0 and TPL-006-0 likewise dealt with Regional Entity reliability assessments and data to be provided to NERC. In NERC's Oct. 19, 2011 Petition in Docket No. RM12-1 to approve TPL-001-2, NERC requested to withdraw the two pending Reliability Standards: TPL-005-0 "Regional and Interregional Self-Assessment Reliability Reports", and TPL-006-0.1 "Data From the Regional Reliability Organization Needed to Assess Reliability". NERC stated that the requirements from

these two Reliability Standards not approved in FERC Order No. 693 have been moved to Sections 803 and 804 of the NERC Rules of Procedure.
Yes
We do not believe a standard is necessary to accomplish the stated goal. This data collection activity could be handled with appropriate revisions to NERC's Rules of Procedure.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
We propose that the "Need Statement" be revised for the following two reasons: a. to limit the applicability to the BES, b. to exclude the verification of system models as a specific need for this standard. We propose the following wording be considered: "PRC-002 is being revised to ensure adequate BES data is captured to enable effective post event analysis following a BES disturbance. (Note that the development of PRC-002-2 under Project 2007-11 was made informal in 2011.) The emphasis will not be on what equipment may be used to capture this data, but on ensuring that the requisite data is captured. PRC-002-2 will also include the pertinent requirements of PRC-018-1 that will allow that Standard to be retired. Utilization of this data will allow the entity to improve system reliability through BES system improvement." And the wording under Brief Description should also be changed to the following for consistency: "By this Standard the Drafting Team will establish the requirements for capturing BES disturbance data to enable effective post event analysis following a BES disturbance. The standard drafting team (SDT) will review PRC-002 and any NERC approved Regional Standard PRC-002."
Yes
Yes
We think it is not appropriate to assign under the Detailed Description the responsibility of the functional entities. We recommend the fourth paragraph be changed as follows: "It is envisioned that the Transmission Owners and Generator Owners will be responsible for the bulk of the Requirements in this Standard and that the Planning Coordinators or Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data."
Group
ACES Standards Collaborators
Jason Marshall
Yes

We agree that SAR clearly identifies the scope of work to be performed.
Yes
We agree that the Transmission Owner and Generator Owner are the correct applicable entities that will be required to provide sequence of event, dynamic disturbance and fault event data as they will be the owners of the event recording assets. If the standard is developed, we also agree that the planning coordinator and/or reliability coordinator should be considered in the standards development process as the entity that could replace the regional reliability organization and that identifies locations for the installation of event recorders.
No
(1) No, we do not agree that there is a need for this standard. This standard is better suited to be a guideline and, in effect, will indirectly require transmission owners and generator owners to install new equipment. It is our understanding that the Energy Policy Act of 2005 specifically excluded the authority to order the installation of additional equipment. Can a regulator indirectly require a registered entity to perform an action such as installing new equipment that it cannot compel directly? (2) The requirements in the last version of PRC-002-2 are administrative in nature and SAR appears to focus on developing administrative requirements. While the data itself will be valuable to perform post event analysis, the collection of data itself is actually administrative. The real value obtained is in performing the event analysis and model verification. Thus, it would make more sense to require entities to perform post-event analysis and model verification rather than to collect data. The entity would then be responsible for determining what type of data it would need and how to obtain that data. Furthermore, NERC already has an event analysis process and is developing or has recently developed a number of model verification standards such as MOD-026-1 and MOD-027-1. (3) The NERC event analysis process has been very successful. We are unaware of any recent event since this standard was first proposed in 2009 that NERC has not been able to evaluate for lack of data. Before this standard is developed, we suggest that the drafting team review the need for the standard with NERC's Reliability Risk Management department. (4) Many companies are already installing a tremendous number of phasor measurement units (PMU). These units are capable of recording all the necessary data for events analysis. The joint FERC-NERC event report from the Arizona-Southern California outage of September 2011 highlighted the proliferation of the PMUs which facilitate the event analysis. The PMU has become so ubiquitous because DOE has employed a carrot approach of providing funding for their installation. This approach is much more effective than a penalty approach established in an enforcement regime. (5) In the end, we think the directives issued by FERC in the spring of 2007 have been overcome by six plus years of events. The world has changed tremendously. Furthermore, we believe PRC-018 should be retired rather than developing any standard.
No
We believe a guideline that supports the existing events analysis process along with a significant industry educational outreach explaining the benefits of collecting the data would yield better results. Registered entities will pursue projects with reliability benefits if the benefits clearly exist and are well understood. Unfortunately, this standard has the potential to

become a zero defect standard that provides little reliability benefit. For example, we can see the proposed synchronization requirement PRC-002 R12 becoming a zero defect requirement that provides little value with paper compliance violations similar to those experienced with PRC-005. Registered entities will be forced to prove they have synchronized equipment because these kinds of maintenance records are easy to misplace and will likely lead to violations of the requirement. Even if they can show the equipment is currently within tolerances, they will have no paperwork showing they synchronized it and will still be in violation even though the end result, synchronized equipment, is the desired result.
Individual
Oliver Burke
Entergy Services, Inc.
No
There is no clear scope of the project presented in the SAR Brief Description. The scope should define what disturbance data needs to be collected and why it is important (objectives of what the standard is to accomplish). As presented, the SAR does not clearly define what the new standard is trying to accomplish and how the new standard will addresses industry needs is for improving the reliability of the BES. (See Q5 comments.)
Yes
Yes
However, the SAR is not clear in that it is not clearly define what “power system” data needs to be collected and why it is important for post event analyses and verification of system models. The specific “Power system” data that would be beneficial needs to be listed along with a justification why the collection of this data is important for improving the reliability of the Bulk Electrical System (BES).
The purpose section is totally deleted, so the SAR does not contain a proper purpose. The Detailed Description is not clear as to what are the objectives of the standard. Information provided are items that need to be considered when drafting the standard, however there are no clear details as to what objectives are (and their basis) nor the equipment that should be within the scope of the standard (e.g., generating unit size, line voltage, etc.). The SAR is not clear the use of the vague term “power system” in the brief description is unclear. Does “power system” imply the Bulk Power System, Bulk Electric System, or generating equipment?
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes

Austin Energy (AE) suggests the SDT consider type of equipment as well as required data. Doing so will ensure checks and balances. That is, the requirements should not specify data without considering the technological capability of the equipment commonly used in the industry.
No
The SAR indicates there may be a role for the Transmission Operator and Generator Operator. The NERC Functional Model Version 5 demonstrates that designing, installing and maintaining facilities is more appropriate to the Transmission Owner and Generator Owner functions.
Yes
Austin Energy (AE) supports a standard that increases clarity, especially regarding responsibilities.
Austin Energy (AE) supports revision of the Disturbance Monitoring standards to close out some "fill-in-the-blank" issues.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela R. Hunter
Yes
No
The GO should not be included – see comments under Question 3.
No
From the GO perspective, post events analysis typically is able to be performed using relay operation records stored within the protective relaying coupled with unit control system historical data. The need for additional high speed data capture equipment, to date, has not been justified from a GO/GOP perspective. The benefit/cost value has not been sufficient to drive the widespread installation of such equipment. The cost for GO/GOP to add DME to each generating facility can be significant due to the design, equipment, and installation costs.
Yes
If the information is needed to verify system models, those entities that create and use the models should make the investment to install equipment needed for those studies.
Individual
Scott Langston
City of Tallahassee
Yes

No
TAL believes the same goal could be accomplished by voluntary efforts.
No
TAL believes voluntary efforts on the part of each entity could be used to provide disturbance monitoring, or an alternative is to leave it up to each region to decide what is needed.
No comment
Group
IRC-SRC
Terry Bilke
No
While we agree that the SAR describes the work the team plans to undertake, we don’t agree with the proposed approach.
No
The project background page outlines that the need for the change is to address the “fill in the blank” issue where there are differences among regions. The proposed SAR makes matters significant worse in that rather than 7 regions, there will be over 100 RCs and PCs involved. In fact, NERC has acknowledged that there are areas where there are no PCs. What is planned for the gaps and overlaps?
No
We don’t agree with the need as proposed. There could be a general requirement for providing DME data for events analysis and modeling purposes. We would suggest the drafting team investigate the ability to put this in the Rules of Procedure or as a standing Section 1600 data request as opposed to a standard.
We are in favor of having disturbance monitoring equipment (DME) with common capabilities in the field, but we have concerns with the SAR’s approach. The SAR proposes to fix a “fill in the blank” problem (where each Region has a specification for DME and a process to collect information) by handing off the responsibility to the Planning Coordinator and Reliability Coordinator. This will exacerbate the problem in that there are more Planning Coordinators (80 according to the NERC Registry) than there are Regions and there is no direct alignment or mapping of transmission owners, transmission planners, generator owners and their respective Planning Coordinator (if they even have one). This will increase the balkanization and add gaps. We would recommend that the NERC Planning Committee develop a common specification and approach to be used for all North America. If the goal of PRC-002 is to enable a data stream for modeling and disturbance analysis, there should be a single standard for provision of such data or a provision included in the Rules of Procedure or a standing Section 1600 data request.
We recommend a thoughtful approach to the disposition of requirements in the standards that

apply to the Regional Reliability Organization. Many of these things are no longer done and should be removed from the standards. Some are procedural processes that need not be in the standards, but rather enforced through regional agreements. A few of the items should be codified in the Rules of Procedure. If some of requirements have been taken over by Reliability Coordinators, the applicable function in the standard should change. Finally, NERC needs to address who is the Planning Coordinator in an area where none is defined. We also need to realize that if the goal is to eliminate a "fill in the blank" issue, the solution is not to just move the blanks.
Individual
Brett Holland
Kansas City Power & Light
No
We are concerned with the comment regarding the use of this data to verify system models. The primary intent of the data is to analyze system events including assisting in determining proper relay operation. We feel that any additional evaluation of the data would not be very helpful. To use the data as discussed, the configuration of the system would be needed including what generation was operating.
No
While we see a need for consistency at least across an interconnection for the specification and collection of disturbance data, that consistency is probably best provided by a minimum of oversight. Pulling the Reliability Coordinator and Planning Coordinator into this may compartmentalize the requirements even more than was originally thought in the regional standard set-up. Additionally, there are concerns as to just what the role the Reliability Coordinator and Planning Coordinator will be in determining locations for the recording equipment. If the locations are to be specified within an Reliability Coordinator footprint that's one item but if the Reliability Coordinator is to be actively involved in making the determinations then it may be outside the normal operating horizon associated with the Reliability Coordinator function.
Yes
Utilizing a standard ensures consistency in establishing the requirements for DME across North America. Perhaps some consideration could be given to letting the standard provide overview or generic requirements associated with DME but then the details be provided in a guideline or best practices document. However, given this there may then be a tendency for the regions to add additional details in regional standards which are more in-depth than the NERC standard.
We would suggest that the drafting team give consideration to grandfathering existing Disturbance Monitoring Equipment installations in the new standard. Several entities have invested significant funds in this equipment and some sort of consideration for this equipment is definitely well deserved. The standard needs to clearly specify that any maintenance plans for relays associated with Disturbance Monitoring Equipment would be covered in PRC-005

rather than in PRC-002. Stand-alone Disturbance Monitoring Equipment would be covered in PRC-002. There was additional information that was made available during the webinar held on May 22, 2013 which was beneficial to understanding just where the standard is going. It would have been helpful for all if that information could have been made available earlier in the comment period.
Individual
Daniela Hammons
CenterPoint Energy Houston Electric, LLC
No
CenterPoint Energy believes a new standard is not needed at this time; therefore, the revised SAR is not needed. Please see response to Questions 3 and 4 below.
No
CenterPoint Energy believes a new standard is not needed at this time; therefore, the revised SAR is not needed. Please see response to Questions 3 and 4 below.
No
CenterPoint Energy does not believe there is a need for a new standard at this time. Please see response to Question 4.
CenterPoint Energy believes there are already regional requirements in place in ERCOT that address many of the items identified in the draft SAR, namely fault and sequence of events data. For example, ERCOT Nodal Operating Guide requirements presently specify the following disturbance monitoring equipment requirements: • Equipment types • Triggering requirements • Location requirements • Data recording requirements • Data retention/reporting requirements (format, elements reported, three-year retention period) • Maintenance requirements • Annual equipment reporting • Review process for DME equipment location Additionally, PRC-018-1 already requires entities to follow RRO requirements, and it includes requirements for: • Time sync and data availability • Maintenance program • Data retention FERC and NERC prepared a report dated April 2012 for the Arizona-Southern California outages of September 2011 indicating that disturbance monitoring data was available in this region for facilitating a quick turnaround of a complex event analysis. Similarly, FERC and NERC prepared a report dated August 2011 for the Southwest cold weather event of February 2011. Furthermore, PRC-004 requires analysis and mitigation of transmission protection system misoperations. Event data assists Entities in recreating the sequence of events needed for cause analysis and mitigation development; therefore, Entities already have un-written requirements to install sufficient recorders to meet PRC-004.
CenterPoint Energy believes existing requirements in PRC-018-1 should be reviewed by the team for inclusion in Phase 2 of the Paragraph 81 project, for example, requirements R3 and R5. The VRF for each requirement is “Lower” and the requirements have not been identified as Tier 1, 2, or 3 in the 2013 Actively Monitored List. Furthermore, PRC-018-1 is not a performance-based standard but rather a standard for analytical purposes. This information

can be gathered through other existing means, such as NERC Section 400 of the NERC Rules of Procedure.
Group
SPP Standards REview Group
Robert Rhodes
No
We are concerned with the comment regarding the use of this data to verify system models. The primary intent of the data is to analyze system events. The SAR, and subsequent standard, should restrict itself to just that. Model validation is another issue for another drafting team and should be covered in a separate project.
No
While we see a need for consistency at least across an interconnection for the specification and collection of disturbance data, that consistency is probably best provided by a minimum of oversight. Pulling the RCs and PCs into this may compartmentalize the requirements even more than was originally thought in the regional standard set-up. Additionally, there are concerns as to just what the role of the RC and PC will be in determining locations for the recording equipment. If the locations are to be specified within an RC footprint that's one item but if the RC is to be actively involved in making the determinations then it may be outside the normal operating horizon associated with the RC function.
Yes
Utilizing a standard ensures consistency in establishing the requirements for DME across North America. Perhaps some consideration could be given to letting the standard provide overview or generic requirements associated with DME but then the details be provided in a guideline or best practices document. However, given this there may then be a tendency for the regions to add additional details in regional standards which are more in-depth than the NERC standard.
One way to minimize the oversight of the specification would be for the PC to take an active role is developing the requirements in either the guideline or best practices document which would serve as the source for this type of information.
We would suggest that the drafting team give consideration to grandfathering existing DME installations in the new standard. Several entities have invested significant funds in this equipment and some sort of consideration for this equipment is definitely well deserved. The standard needs to clearly specify that any maintenance plans for relays associated with DME would be covered in PRC-005 rather than in PRC-002. Stand-alone DME would be covered in PRC-002. There was additional information that was made available during the webinar held on May 22, 2013 which was beneficial to understanding just where the standard is going. It would have been helpful for all if that information could have been made available earlier in the comment period, especially for those who could not participate in the webinar.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2007-11 Disturbance Monitoring

The Project 2007-11 SDT thanks all commenters who submitted comments on the Standard Authorization Request (SAR). There were 44 sets of comments, including comments from approximately 145 different people from approximately 85 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

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

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

Summary Consideration of all Comments Received

The main change in the Revised SAR was that the PRC-002-2 is to capture the appropriate data to analyze power system disturbances and not the type of equipment that should be used.

Several commenters made suggested wording changes for the Revised SAR. The Standard Drafting Team (SDT) did not intend to repost the Revised SAR so no changes will be made to the wording of the Revised SAR.

The Drafting Team understands there are misunderstandings and interest in how the MVA short circuit study was performed and how it is applied in the standard. In order to facilitate industry understanding, gather different industry viewpoints, and answer questions - the SDT is holding two technical conferences. The first conference is in Tempe, AZ July 30 and 31, 2013 and the second conference is in Atlanta, GA August 6 and 7, 2013. The conferences will allow attendees to have other questions concerning the standard answered, provide feedback, and it will provide the SDT with additional information to make needed revisions to the standards prior to the comment period and ballot posting.

Please see the summary responses for each question for detailed responses.

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Helen Lainis	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5

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

12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1

2.	Group	David Thorne	Pepco Holdings Inc.	X		X							

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

3.	Group	Joseph DePoorter	Madison Gas and Electric Company	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Breene	WPS	MRO	3, 4, 5, 6
4.	Jodi Jenson	WAPA	MRO	1, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Alice Ireland	XCEL	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6
9.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
10.	Scott Nickels	RPU	MRO	4
11.	Terry Harbour	MEC	MRO	1, 3, 5, 6
12.	Marie Knox	MISO	MRO	2
13.	Lee Kittelson	OTP	MRO	1, 3, 4, 5

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

14. Scott Bos	MPW	MRO	3, 4, 5
15. Tony Eddleman	NPPD	MRO	1, 3, 5
16. Mike Brytowski	GRE	MRO	1, 3, 5, 6
17. Dan Inman	MPC	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Patrick Brown	Essential Power, LLC					X					

Additional Member	Additional Organization	Region	Segment Selection
1. Allen Schriver	NextEra		5
2. Steve Berger	PPL Susquehanna, LLC		5
3. Joe Crispino	PSEG Fossil, LLC		5
4. Pamela Dautel	IPR-GDF Suez Generation NA		5
5. Dan Duff	Liberty Electric Power		5
6. Mikhail Falkovich	PSEG		5
7. Gary Kruempel	MidAmerican Energy Company		5
8. Katie Legates	American Electric Power		5
9. Don Lock	PPL Generation, LLC		5
10. Joe O'Brien	NIPSCO		5
11. Dana Showalter	e.on		5
12. William Shultz	Southern Company		5
13. Mark Young	Tenasks, Inc		5

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

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Brandy Spraker	Transmission Reliability Engineering and Controls	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. George Pitts		SERC	1
2. Marjorie Parsons		SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Lloyd A. Linke	Western Area Power Administraton - Upper	X					X				

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

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

				1	2	3	4	5	6	7	8	9	10
8.	Group	Larry Raczkowski	FirstEnergy Corp	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FirstEnergy Corp	RFC	1
2.	Cindy Stewart	FirstEnergy Corp	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6

				1	2	3	4	5	6	7	8	9	10
9.	Group	Brent Ingebrigtson	LG&E and KU Services	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registred Affiliates	RFC	5
3.			WECC	5
4.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
5.			NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6

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

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Jason Marshall	ACES						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Jackson	Buckeye Power	RFC	3, 4
2.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
3.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
6.	John Shaver	Southwest Transmission Cooperative	WECC	1

12.	Group	Terry Bilke	MISO		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Stephanie Monzon	PJM	RFC	2
2.	Greg Campoli	NYISO	NPCC	2
3.	Ben Li	IESO	NPCC	2
4.	Ali Miremadi	CAISO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Kathleeen Goodman	ISO-NE	NPCC	2
7.	Matthew Morais	ERCOT	ERCOT	2

13.	Group	Robert Rhodes	Southwest Power Pool		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Shannon Bellinghausen	Xcel Energy	SPP	1, 3, 5, 6
3.	Andrew Evans	Westar Energy	SPP	1, 3, 5, 6
4.	Greg Hill	Nebraska Public Power District	MRO	1, 3, 5
5.	Shawn Jacobs	Oklahoma Gas & Electric	SPP	1, 3, 5
6.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
7.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
8.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
9.	Frankie Smith	Kansas City Power & Light	SPP	1, 3, 5, 6
10.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5,

14.	Individual	test	test						X				
15.	Individual	Ed Croft	Puget Sound Energy	X		X		X					

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Bill Middaugh	Bill Middaugh	X									
17.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
18.	Individual	Pamela R. Hunter	Southern Company Operations Compliance	X		X		X	X				
19.	Individual	Michael Moltane	ITC	X									
20.	Individual	Michael Falvo	Independent Electricity System Operator		X								
21.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
22.	Individual	Anthony Jablonski	ReliabilityFirst										X
23.	Individual	Gustavo Brunello	Gustavo Brunello										
24.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
25.	Individual	Wryan Feil	Northeast Utilities	X									
26.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
27.	Individual	John Bee	Exeln and its affiliates	X		X							
28.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
29.	Individual	Jonathan Meyer	Idaho Power Company	X									
30.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
31.	Individual	David Jendras	Ameren	X		X		X	X				
32.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					
33.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
34.	Individual	Bill Fowler	City of Tallahassee			X							
35.	Individual	Karen Webb	City of Tallahassee					X					
36.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
37.	Individual	Chantal Mazza	Hydro QuÃ©bec TransÃ‰nergie	X									
38.	Individual	Andrew Z. Pusztai	american Transmission Company, LLC	X									
39.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
40.	Individual	Oliver Burke	Entergy Services, Inc.	X		X		X	X				
41.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
42.	Individual	Scott Langston	City of Tallahassee	X									
43.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
44.	Individual	Daniela Hammons	CenterPoint Energy Houston Electric, LLC	X									

1. Do you agree the scope of the revised SAR describes the work to be performed in this project? If not, please explain.

Summary Consideration: There were 42 responses to this question. Of these, 14 did not agree with the scope, and 28 did agree.

The common threads of the comments were:

1. Suggestions to clarify applicability to the BES rather than the BPS, power system, or some other designation.
2. Apparent misconception that the standard will be requiring specific equipment.
3. Some suggestions regarding maintenance of the recording capability.
4. Concerns with statements that the information may be used to verify system models.
5. Requests for clarification as to what events qualify as those for which recordings are to be available.
6. Concerns that it is not clear what the disposition of PRC-018 will be.
7. Some misunderstandings of the MVA short circuit study criteria and how it is to be used.
8. Suggestions for revisions to the “Need” statement and to the “Brief Description” section.
9. One entity is of the opinion that SOER is not needed for Transmission Owners.
10. One entity is of the opinion that the information can be gathered under the NERC Rules of Procedure rather than through a Reliability Standard.

The Standard SDT (SDT) appreciates the comments and believes that some clarifications are needed. The SDT believes several very important aspects of the SAR and intended standard have been misunderstood. The SDT is taking the approach to describe the technical parameters needed for the data recording capability to provide for the adequate gathering of sufficient data with accurate time stamping to provide for the analysis of wide-spread system disturbances. The SDT will clarify which categories of events, as described in the NERC Events Analysis Process documents, were considered in the drafting of the standard.

The SDT will clarify that the standard applies only to locations that are part of the BES. The SDT acknowledges that information other than this data, such as system topology and what generation is online, will be required to be used in combination with this disturbance monitoring data and allow for disturbance analyses.

The SDT is not planning to include a maintenance requirement. The SDT has deliberately not specified what equipment must be used, but described the type of information that is needed and the time-stamping and sampling parameters that will make the information usable in disturbance analyses. The SDT is of the opinion that it should not matter what equipment is used to provide for the recordings, only that the information is provided and meets the standard requirements. This will also provide for the use of any existing or future technology that can meet or exceed the requirements.

One entity questioned whether the loss of a GPS clock, which is normally functional at a given location, would automatically result in a violation of the standard. The SDT recognizes that all such systems have occasional failures or maintenance requirements. The SDT will address the availability and maintenance aspects in the standard, with the intent being that it is recognized that such failures do occur. There will be response requirements for such occurrences, but the SDT is of the opinion that it will be rare for such occurrences, and there will be other locations which will continue to function. The loss of a few locations should not make the information unusable.

The SDT agrees with commenters that state that requiring the use of disturbance monitoring information to verify system models goes beyond the scope of the project. The SDT intends to pursue the development of a guideline document to go along with the standard and may include statements that such practices as verification of system models is not required by the standard, but that it may be considered a good utility practice to do so insofar as the information is relevant and usable for the purpose.

The PRC-002-2 requirements will allow PRC-018-1 to be retired.

The SDT has discussed what events will require data recordings. The SDT has not included this issue in the SAR nor does the SDT plan to include requirements for it in the standard. Instead the SDT has focused on the entities - NERC, the Regions or RCs – that the standard authorizes to make requests for the data, after noting the typical situations in which these entities are most likely to request the data; for instance, Event Categories 3, 4, and 5 in NERC's Event Analysis Program. The SDT has made a significant change in approach since the posting of the first draft in 2009. The approach now will not be equipment centric and will instead address the identification of locations for which Sequence of Events Recording (SOER), Fault Recording (FR), and Dynamic Disturbance Recording (DDR) capability is to be required. Further, the standard will describe the technical methodology using the MVA short circuit level to determine the locations of Sequence of Events Recording (SOER) and Fault Recording (FR), and specify the functional entities that are responsible to either identify the locations or to provide the capability at those locations. The NERC Standards Committee has approved the use of a trial application in this project of the Cost Effectiveness Analysis Process (CEAP).

The Standard Drafting Team reviewed both the "Need" and the "Brief Description" Sections in response to comments. The STD does not feel that those Sections need revision.

NERC Legal Staff was consulted regarding the collection of disturbance monitoring data under the NERC Rules of Procedure, and with reference to the FERC rule for FAC-003-2 it was determined that the collection of data was enforceable.

As stipulated in the standard, the collecting of not only FR and DDR data, but SOER data is needed for event analysis. The Transmission Owner is in a position to capture this data.

Organization	Yes or No	Question 1 Comment
Ameren	No	(1)The slides from the May 22nd NERC webinar indicate considerable PRC-002-2 draft 1 development has already occurred. Based on our experience this draft appears to require a density of disturbance monitoring well in excess of what we believe is needed for disturbance analysis. The SDT has explained the difficulties of developing the August 2003 Blackout sequence of events. (a) Have NERC and its various entities experienced the same level of difficulty in determining a sequence of events since PRC-018-1 and regional criteria have been implemented? (b) For our understanding how many disturbances have NERC and Regional Entities analyzed since June 18th, 2007? (2) Based on our experience we believe that there is now sufficient information to determine the sequence of events, and that regional and NERC disturbance analyses are infrequent. Thankfully widespread disturbances are rare. We understand the importance of disturbance analysis and support an appropriate amount of the correct monitoring equipment, in the right locations, to capture what is necessary to determine sequence of events and system response to determine root cause. (3) We believe that the 1500MVA threshold is very low, too close to current load levels. If 1500MVA is retained, then 20% is too high.(4) We agree that short circuit MVA is a valid factor to consider, however, we also believe that topology is just as important to yield proper placement of disturbance monitors.(5) We request that if <200kV locations are to be included then a bifurcated criteria is warranted and should be used. Major generating sources should be captured, and a much lower percentage of buses are required below 200kV.
Response: The SDT thanks you for your comment.		
CenterPoint Energy Houston Electric, LLC	No	CenterPoint Energy believes a new standard is not needed at this time; therefore, the revised SAR is not needed. Please see response to

Organization	Yes or No	Question 1 Comment
		Questions 3 and 4 below.
Response: The SDT thanks you for your comment.		
Dominion Resources Services, Inc.	No	Dominion believes the scope needs to be more clearly defined to ensure the capturing and analysis of disturbances on the "Bulk Electric System" as opposed to the nebulous "power system."
Response: The SDT thanks you for your comment.		
Nebraska Public Power District	No	Focusing on data rather than equipment to provide the required recorded information has benefits however this creates some concerns. For example, assume we have a GPS clock and relay that can meet the 2ms criteria however prior to an event the clock loses time due to an internal error (these devices are not perfect) so the relay no longer has the correct time of the event. If this data is then requested by the RE would this be a compliance violation because the data is wrong even though the equipment is capable of meeting the criteria? Will this data be audited?Even though the focus is on data and equipment capabilities and not specifying stand alone or relaying equipment to record data it seems there should be some discussion on the maintenance differences. I recommend that protective relays used for DME type functions should not be in two maintenance plans.
Response: The SDT thanks you for your comment.		
Western Area Power Administraton - Upper Great Plains Region	No	Including the statement that "This information will also be used to verify system models" goes beyond the purpose of ensuring that the requisite data is captured. Adding requirements for verifying system models will likely over-complicate the standard and delay its ultimate industry approval.

Organization	Yes or No	Question 1 Comment
Response: The SDT thanks you for your comment.		
Public Service Enterprise Group	No	The standard produced needs to clarify what events qualify as those for which registered entities are responsible to acquire, save and report SOE, FR and DDR data per the standard. The standard should clarify these events with reference to criteria already established and followed by NERC and/or others such as Regions or ISOs etc in their analysis programs/practices. For example, regarding data for NERC the standard could set out which of the Categories defined in NERC Events Analysis program the data would be required for. At the end of the day no entity wants or should be surprised with a request for data from any entity after any event. And requests for data via this standard need to be reasonable and justifiable by, for instance, the size and/or impact of the event.
Response: The SDT thanks you for your comment.		
Entergy Services, Inc.	No	There is no clear scope of the project presented in the SAR Brief Description. The scope should define what disturbance data needs to be collected and why it is important (objectives of what the standard is to accomplish). As presented, the SAR does not clearly define what the new standard is trying to accomplish and how the new standard will addresses industry needs is for improving the reliability of the BES. (See Q5 comments.)
Response: The SDT thanks you for your comment.		
Northeast Power Coordinating Council	No	There is no specific mention of the removal of the PRC-018 R6 Maintenance requirement in the SAR. The original SDT was moving it to PRC-005. R6 is ambiguous, and if included needs to be revised or else should be removed. It should be stipulated that DFR/DDR should be verified semi-annually to ensure that the device is receiving analog signals.

Organization	Yes or No	Question 1 Comment
		The Need Section should be revised to limit the applicability to the BES, and to exclude the verification of system models as a specific need for this standard. Suggest the following wording for the Need Section:PRC-002 is being revised to ensure adequate BES data is captured to enable effective post event analysis following a BES disturbance. (Note that the development of PRC-002-2 under Project 2007-11 was made informal in 2011.) The emphasis will not be on what equipment may be used to capture this data, but on ensuring that the requisite data is captured. PRC-002-2 will also include the pertinent requirements of PRC-018-1 that will allow that Standard to be retired. Utilization of this data will allow the entity to improve system reliability through BES system improvement. The wording under Brief Description of Proposed Standard Modifications/Actions should also be revised to the following for consistency:By this Standard the SDT will establish the requirements for capturing BES disturbance data to enable effective post event analysis following a BES disturbance. The Standard SDT (SDT) will review PRC-002 and any NERC approved Regional Disturbance Monitoring Standard.
Response: The SDT thanks you for your comment.		
Tacoma Power	No	Under the Detailed Description section, it is noted that “the Planning Coordinators and Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data.” However, under the Technical Analysis Performed to Support Justification section, it is noted that “a study of multiple systems across the continent was done to determine the locations needed to record sufficient power system data for Sequence of Events, Faults, and Dynamic Disturbances based on three phase bolted short circuit MVA thresholds.” These two statements appear to be contradictory. In one case, Planning Coordinators and Reliability Coordinators are to specify locations. In the other case, it can be inferred that sufficient research has been conducted already to propose criteria for

Organization	Yes or No	Question 1 Comment
		specifying locations that would be applicable to the standard. If Planning Coordinators and Reliability Coordinators will be responsible to specify locations, there should be clear division of authority between these two functional entities. Furthermore, there should be some responsibility for Planning Coordinators and Reliability Coordinators to justify on a technical and financial basis the locations that they specify since Generator Owners and Transmission Owners will bear the direct cost of any new infrastructure to comply with the standard.
Response: The SDT thanks you for your comment.		
Kansas City Power & Light	No	We are concerned with the comment regarding the use of this data to verify system models. The primary intent of the data is to analyze system events including assisting in determining proper relay operation. We feel that any additional evaluation of the data would not be very helpful. To use the data as discussed, the configuration of the system would be needed including what generation was operating.
Response: The SDT thanks you for your comment.		
Southwest Power Pool	No	We are concerned with the comment regarding the use of this data to verify system models. The primary intent of the data is to analyze system events. The SAR, and subsequent standard, should restrict itself to just that. Model validation is another issue for another SDT and should be covered in a separate project.
Response: The SDT thanks you for your comment.		
Northeast Utilities	No	We propose that the “Need Statement” be revised for the following two reasons:a. to limit the applicability to the BES,b. to exclude the verification of system models as a specific need for this standardWe

Organization	Yes or No	Question 1 Comment
		propose the following wording be considered:”PRC-002 is being revised to ensure adequate BES data is captured to enable effective post event analysis following a BES disturbance. (Note that the development of PRC-002-2 under Project 2007-11 was made informal in 2011.) The emphasis will not be on what equipment may be used to capture this data, but on ensuring that the requisite data is captured. PRC-002-2 will also include the pertinent requirements of PRC-018-1 that will allow that Standard to be retired. Utilization of this data will allow the entity to improve system reliability through BES system improvement.” And the wording under Brief Description should also be changed to the following for consistency:”By this Standard the SDT will establish the requirements for capturing BES disturbance data to enable effective post event analysis following a BES disturbance. The standard SDT (SDT) will review PRC-002 and any NERC approved Regional Standard PRC-002.” Under Goals we recommend the following wording: "Sufficient Adequate (limited redundancy) Sequence of Events, Fault, and Dynamic Disturbance recordings to analyze power system disturbances must be captured and accessible." Where meansAdequate means: (lawfully and reasonably sufficient)Sufficient means: (enough to meet the needs of a situation or condition)
Response: The SDT thanks you for your comment.		
Consolidated Edison Co. of NY, Inc.	No	We propose that the “Need Statement” be revised for the following two reasons:a. to limit the applicability to the BES,b. to exclude the verification of system models as a specific need for this standard.We propose the following wording be considered:”PRC-002 is being revised to ensure adequate BES data is captured to enable effective post event analysis following a BES disturbance. (Note that the development of PRC-002-2 under Project 2007-11 was made informal in 2011.) The emphasis will not be on what equipment may be used to capture this data, but on ensuring

Organization	Yes or No	Question 1 Comment
		that the requisite data is captured. PRC-002-2 will also include the pertinent requirements of PRC-018-1 that will allow that Standard to be retired. Utilization of this data will allow the entity to improve system reliability through BES system improvement." And the wording under Brief Description should also be changed to the following for consistency:"By this Standard the SDT will establish the requirements for capturing BES disturbance data to enable effective post event analysis following a BES disturbance. The standard SDT (SDT) will review PRC-002 and any NERC approved Regional Standard PRC-002."
Response: The SDT thanks you for your comment.		
MISO	No	While we agree that the SAR describes the work the team plans to undertake, we don't agree with the proposed approach.
Response: The SDT thanks you for your comment.		
Madison Gas and Electric Company	Yes	Although the NSRF agrees with capturing BES event data, there are entities who currently have devices installed which gather DME data. The issue is how can a Standard (such as PRC-002) mandate the purchasing of such equipment? The cost could be substantial for both large and small applicable entities.
Response: The SDT thanks you for your comment.		
City of Austin dba Austin Energy	Yes	Austin Energy (AE) suggests the SDT consider type of equipment as well as required data. Doing so will ensure checks and balances. That is, the requirements should not specify data without considering the technological capability of the equipment commonly used in the industry.
Response: The SDT thanks you for your comment.		

Organization	Yes or No	Question 1 Comment
Exeln and its affiliates	Yes	ComEd believes that fault recording equipment and dynamic disturbance recording equipment that is time synchronized by a GPS Satellite clock are sufficient to analyze disturbances. Although separate sequence of event recording may be useful for Generator Owners/Operators, it should not be required for Transmission Owners. Modern microprocessor relays already include a great deal of built-in sequence of event recording capability. A requirement for SOE capability is thus not needed in a standard and would only be burdensome. Additionally, experience at Exelon has shown that investigation of power system events very rarely requires the use of this built-in sequence of event records capability to determine the root cause of an event.
Response: The SDT thanks you for your comment.		
FirstEnergy Corp	Yes	FirstEnergy (FE) prefers this scope for this SAR as opposed to a more prescriptive methodof previous standard, ie, this standard will not specify what equipment must be used to capture this data.
Response: The SDT thanks you for your comment.		
Duke Energy	Yes	However, we don't believe that this work necessarily must be accomplished in a reliability standard, but could instead be accomplished under the authority of NERC's Rules of Procedure for data collection and Events Analysis Program. See our responses to questions 3 and 4 below.
Response: The SDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration ("ICLP") agrees that the DME standard should focus on the data desired, not the equipment type. The technology is changing rapidly and PRC-002-2 should not inhibit the use of the latest

Organization	Yes or No	Question 1 Comment
		recorder capabilities.
Response: The SDT thanks you for your comment.		
ReliabilityFirst	Yes	ReliabilityFirst agrees that the scope of the revised SAR adequately describes the necessary work to be performed in this project. ReliabilityFirst agrees that the shift in focus of the SAR to ensure that the requisite disturbance data is captured (rather than prescribing the equipment which must be used to capture disturbance data) is an appropriate course of action.
ACES	Yes	We agree that SAR clearly identifies the scope of work to be performed.
Pepco Holdings Inc.	Yes	
Essential Power, LLC	Yes	
Transmission Reliability Engineering and Controls	Yes	
LG&E and KU Services	Yes	
Puget Sound Energy	Yes	
Bill Middaugh	Yes	
PacifiCorp	Yes	
Southern Company Operations Compliance	Yes	
Independent Electricity System	Yes	

Organization	Yes or No	Question 1 Comment
Operator		
Wisconsin Electric Power Company	Yes	
Gustavo Brunello	Yes	
Manitoba Hydro	Yes	
South Carolina Electric and Gas	Yes	
Idaho Power Company	Yes	
American Electric Power	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Hydro QuÃ©bec TransÃ‰nergie	Yes	
american Transmission Company, LLC	Yes	
City of Tallahassee	Yes	

2. **The revised SAR identifies a list of functional entities that may be assigned responsibility for requirements in the set of standards addressed by this SAR. Do you agree with the list of proposed applicable functional entities? If no, please explain.**

Summary Consideration:

The Standard SDT (SDT) appreciates industry comments pertaining to the list and responsibilities of proposed functional entities addressed in this SAR. Overall, 23 commenters replied 'Yes' to this question while 15 replied 'No'. Of the respondents who provided additional comments, many were in consensus regarding specific areas. These areas, and the SDT's response to these concerns, are provided below:

•*The Transmission Owner (TO) and Generator Owner (GO) are the primary applicable entities for this Standard.* The SDT agrees that the TO and GO play a critical role in ensuring the capability of Disturbance Monitoring recording since they are the ultimate owners of the equipment. Specifically, TOs generally perform system fault studies and have the most direct involvement with Fault Recording (FR) and Sequence of Events Recording (SOE) and its placement. As the SAR addresses, the TOs and GOs will be responsible for the bulk of Requirements in this Standard. However, the Planning Coordinator and Reliability Coordinator have a wide-area view pertaining to location placement of Dynamic Disturbance Recording (DDR).

•*The Generator Owner (GO) should not be included as an applicable functional entity.* Generator Owners (GOs) play a critical role in providing FR, SOE, and DDR capability. Generator Owners (GOs) are responsible to provide Fault Recording (FR) and Sequence of Events Recording (SOE) at generation interconnection facilities at sites selected by the TO using the MVA criteria, and Dynamic Disturbance Recording (DDR) at generating plants above a given MVA level.

•*Further explanation and clarity should be provided for the role of the Planning Coordinator (PC) or Reliability Coordinator (RC) in the applicable functional entities.* The requirements for Dynamic Disturbance Recording locations incorporate wide-area (Regional or Interconnection-wide) perspective of the Bulk Electric System (BES). The PC or RC has the responsibility of determining the locations for DDR, maintaining a list of those locations, and coordinating that information with the TOs and GOs in its footprint. Their authority on placement set forth in this Standard. Many PCs and RCs, or their staffs, have already worked in conjunction with their TOs and GOs to perform analyses of DDR placement. Furthermore, in some Regions the RC, or its staff is better suited, to be the applicable functional entity rather than the PC.

•*The Transmission Operator (TOP) and Generator Operator (GOP) should be removed from applicability of this Standard.* The SDT agrees with this statement and has removed the TOP and GOP from any applicability pertaining to this Standard.

•*Distribution Provider should also be included depending on the specific requirements developed.* The SDT has considered this comment. The Requirements being developed pertain to Disturbance Monitoring for the Bulk Electric System (BES). For this purpose, the Transmission Owner (TO) and Generator Owner (GO) are best suited to accomplish adequate coverage for capturing BES Disturbances.

•*Continent-wide standard and addressing the "fill in the blank" issue for Planning Coordinator (PC) and Reliability Coordinator (RC).* The intent of this Standard is to provide a continent-wide standard that provides adequate coverage for Disturbance Monitoring. Regional differences have minimally been addressed in certain Requirements in this Standard based on system dynamic performance; however, regional variances have been minimized. The SDT would like to again clarify that the PC and RC are included as applicable functional entities in this Standard for the location Requirements pertaining to Dynamic Disturbance Recording (DDR). However, the location Requirements are no longer "fill in the blank" requirements and it is the responsibility of the PC and RC to determine where these locations and Elements are to be monitored based on the Standards' Requirements. The PC and RC have a wide-area view, and including both allows for regional variances, filling in potential gaps or variances between Regions.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	AEP agrees overall with the functional entities as specified, however it might be necessary to also include Distribution Provider, depending on what specific requirements are eventually developed.
Response: The SDT thanks you for your comment.		
CenterPoint Energy Houston Electric, LLC	No	CenterPoint Energy believes a new standard is not needed at this time; therefore, the revised SAR is not needed. Please see response to Questions 3 and 4 below.
Response: The SDT thanks you for your comment.		
Exeln and its affiliates	No	ComEd does not believe that it is necessary that a disturbance monitoring standard apply to the planning coordinator or reliability coordinator. ComEd is rapidly installing modern protection equipment such that eventually all HV & EHV transmission lines and transformers will be protected by equipment with built-in oscillographic and sequence of events capabilities. By the end of 2015, with or without

Organization	Yes or No	Question 2 Comment
		a standard, all of ComEd's EHV lines will have built-in oscillographic and sequence of events capabilities. Currently, the majority of both HV and EHV line relaying are microprocessor based. Thus, there is no need for any involvement of the planning coordinator or reliability coordinator to determine requirements or locations for oscillographic or sequence of events capabilities. For long term disturbance monitors, ComEd believes the standard would be better served by providing a short list of important circuits that would require stored synchrophasor data or long term disturbance monitoring, i.e. all generators greater than X MW or at the tie point of generating stations greater than Y MW aggregate capacity, stability limited lines or IROLS, etc. This would eliminate the need for involving the planning coordinator or reliability coordinator and target required recording data to the most important circuits only. Also, the minimum amount of useful data should be required to be stored for long term disturbance monitors (positive sequence voltage and current (or one phase of voltage and current) and frequency). MW and MVAR can always be calculated. Including the Reliability Coordinator and/or Planning Coordinator is like creating a fill in the blank standard just with a different entity filling in the blank.
Response: The SDT thanks you for your comment.		
LG&E and KU Services	No	Disturbance Monitoring Equipment (DME) should be required of GOs/GOPs only if the TO determines that this equipment is necessary. Generally, GO/GOPs generally have little or no role in analyzing Disturbances.It may be necessary to add Distribution Providers to the list of Responsible Entities depending on what requirements are eventually developed
Response: The SDT thanks you for your comment.		
Ingleside Cogeneration LP	No	ICLP is not sure what role Planning Coordinators and Reliability Coordinators will play in the updated standard. We believe some caution is in order if the intent is to identify additional locations where DME should be deployed beyond those established through the application of PRC-002-2's criteria. Since the RC and PC decisions will have a cost

Organization	Yes or No	Question 2 Comment
		impact on a Generator Owner, it is important that limits to their authority are established up front - with an allowance for an appeal to NERC if a dispute arises.
Response: The SDT thanks you for your comment.		
Nebraska Public Power District	No	In the past there was desire to have a continent wide standards that did not vary based on regions so the requirements were uniform across the continent. Is it now the goal to accept differences in the requirements by regions? Perhaps clarify if this uniformity is not desired.
Response: The SDT thanks you for your comment.		
Tacoma Power	No	It is not clear what direct role Generator Operators and Transmission Operators would have in the implementation of PRC-002-2. Furthermore, the other functional entities (Reliability Coordinator, Planning Coordinator, Transmission Owner, and Generator Owner) are mentioned elsewhere in the SAR form while Transmission Operator and Generator Operator are not.
Response: The SDT thanks you for your comment.		
FirstEnergy Corp	No	On page 4 of the SAR, Transmission Operator and Generation Operator are included. FE believes that the respective Owner (Transmission and Generation) should be applicable, not the Operator. FE agrees that the applicable entities are the Transmission Owner, Generation Owner, Planning Coordinator and Reliability Coordinator.
Response: The SDT thanks you for your comment.		
Southern Company Operations Compliance	No	The GO should not be included - see comments under Question 3.

Organization	Yes or No	Question 2 Comment
Response: The SDT thanks you for your comment.		
MISO	No	The project background page outlines that the need for the change is to address the "fill in the blank" issue where there are differences among regions. The proposed SAR makes matters significant worse in that rather than 7 regions, there will be over 100 RCs and PCs involved. In fact, NERC has acknowledged that there are areas where there are no PCs. What is planned for the gaps and overlaps?
Response: The SDT thanks you for your comment.		
City of Austin dba Austin Energy	No	The SAR indicates there may be a role for the Transmission Operator and Generator Operator. The NERC Functional Model Version 5 demonstrates that designing, installing and maintaining facilities is more appropriate to the Transmission Owner and Generator Owner functions.
Response: The SDT thanks you for your comment.		
Wisconsin Electric Power Company	No	We are of the opinion that Transmission Owners are the primary applicable entities, with Generator Owner applicability being limited to specific cases (see #5 below). The Transmission Operator and Generator Operator should be removed from applicability to this standard.
Response: The SDT thanks you for your comment.		
Bill Middaugh	No	We believe that the SDT should develop requirements for specifying which locations require Dynamic Disturbance data. That would eliminate the need for including the Planning Coordinator and the Reliability Coordinator. If a coordinating entity is retained in the Applicability, it should only be the Planning Coordinator because the Functional Model does not provide for assigning this type responsibility to the Reliability Coordinator.

Organization	Yes or No	Question 2 Comment
Response: The SDT thanks you for your comment.		
Southwest Power Pool	No	While we see a need for consistency at least across an interconnection for the specification and collection of disturbance data, that consistency is probably best provided by a minimum of oversight. Pulling the RCs and PCs into this may compartmentalize the requirements even more than was originally thought in the regional standard set-up. Additionally, there are concerns as to just what the role of the RC and PC will be in determining locations for the recording equipment. If the locations are to be specified within an RC footprint that's one item but if the RC is to be actively involved in making the determinations then it may be outside the normal operating horizon associated with the RC function.
Response: The SDT thanks you for your comment.		
Kansas City Power & Light	No	While we see a need for consistency at least across an interconnection for the specification and collection of disturbance data, that consistency is probably best provided by a minimum of oversight. Pulling the Reliability Coordinator and Planning Coordinator into this may compartmentalize the requirements even more than was originally thought in the regional standard set-up. Additionally, there are concerns as to just what the role the Reliability Coordinator and Planning Coordinator will be in determining locations for the recording equipment. If the locations are to be specified within an Reliability Coordinator footprint that's one item but if the Reliability Coordinator is to be actively involved in making the determinations then it may be outside the normal operating horizon associated with the Reliability Coordinator function.
Response: The SDT thanks you for your comment.		
Duke Energy	Yes	However, the Transmission Planner and the Transmission Operator should also be included to work in conjunction with the Reliability Coordinator and the Planning

Organization	Yes or No	Question 2 Comment
		Coordinator to identify locations for collecting Dynamic Disturbance Data.
Response: The SDT thanks you for your comment.		
Essential Power, LLC	Yes	The SRT believes it may be necessary to add the Distribution Provider depending on what requirements are eventually developed.
Response: The SDT thanks you for your comment.		
ACES	Yes	We agree that the Transmission Owner and Generator Owner are the correct applicable entities that will be required to provide sequence of event, dynamic disturbance and fault event data as they will be the owners of the event recording assets. If the standard is developed, we also agree that the planning coordinator and/or reliability coordinator should be considered in the standards development process as the entity that could replace the regional reliability organization and that identifies locations for the installation of event recorders.
Response: The SDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
Pepco Holdings Inc.	Yes	
Madison Gas and Electric Company	Yes	
Dominion Resources Services, Inc.	Yes	
Transmission Reliability	Yes	

Organization	Yes or No	Question 2 Comment
Engineering and Controls		
Western Area Power Administraton - Upper Great Plains Region	Yes	
Puget Sound Energy	Yes	
PacifiCorp	Yes	
Independent Electricity System Operator	Yes	
Gustavo Brunello	Yes	
Manitoba Hydro	Yes	
Northeast Utilities	Yes	
South Carolina Electric and Gas	Yes	
Idaho Power Company	Yes	
Ameren	Yes	
Public Service Enterprise Group	Yes	
Hydro QuÃ©bec TransÃ‰nergie	Yes	
american Transmission	Yes	

Organization	Yes or No	Question 2 Comment
Company, LLC		
Consolidated Edison Co. of NY, Inc.	Yes	
Entergy Services, Inc.	Yes	

3. Do you agree there is a need for a standard? Please explain your response.

Summary Consideration:

The Standard SDT (SDT) appreciates industry comments regarding the need for a standard. Overall, 30 commenters replied 'Yes' to this question while 9 replied 'No', thus the consensus of responses was an agreement that there is a need for a standard.

Of the commenters that provided a 'No' response with an explanation, many were in consensus regarding specific areas. These areas, and the SDT's response to these concerns, are provided below:

• '*The standard is better suited to be a guideline and, in effect, will indirectly require transmission owners and generator owners to install new equipment. …the same goal can be accomplished by voluntary efforts.'* The SDT has worked to draft a standard which requires applicable functional entities to record sufficient information to capture the data needed at identified locations to enable post-disturbance analyses. The SDT has deliberately avoided specifying equipment to be installed. The SDT has taken this approach because it recognized the unintended consequences of precluding the use of new technology or other adaptations of other available or, possibly, already existing equipment. The standard is a performance based standard. Further, the capture of the information or data is very important for post-disturbance analysis. A guideline which will indirectly require TO and GO to install new DME equipment or which relies on voluntary efforts may not result in the actual provision of the information that is needed.

•*General requirement for providing DME data for events analysis and modeling purposes that could be put in the Rules of Procedure as opposed to a standard.* The industry approved SAR indicates that this data should be provided as specified in a Reliability Standard. For further discussion on the Rules of Procedure and Section 1600 please refer to the response to Question 4.

Organization	Yes or No	Question 3 Comment
ACES	No	(1) No, we do not agree that there is a need for this standard. This standard is better suited to be a guideline and, in effect, will indirectly require transmission owners and generator owners to install new equipment. It is our understanding that the Energy Policy Act of 2005 specifically excluded the authority to order the installation of additional equipment. Can a regulator indirectly require a registered entity to perform an action such as installing new equipment that it cannot compel directly? (2) The requirements in the last version of PRC-002-2 are administrative in nature and SAR

Organization	Yes or No	Question 3 Comment
		appears to focus on developing administrative requirements. While the data itself will be valuable to perform post event analysis, the collection of data itself is actually administrative. The real value obtained is in performing the event analysis and model verification. Thus, it would make more sense to require entities to perform post-event analysis and model verification rather than to collect data. The entity would then be responsible for determining what type of data it would need and how to obtain that data. Furthermore, NERC already has an event analysis process and is developing or has recently developed a number of model verification standards such as MOD-026-1 and MOD-027-1. (3) The NERC event analysis process has been very successful. We are unaware of any recent event since this standard was first proposed in 2009 that NERC has not been able to evaluate for lack of data. Before this standard is developed, we suggest that the SDT review the need for the standard with NERC's Reliability Risk Management department. (4) Many companies are already installing a tremendous number of phasor measurement units (PMU). These units are capable of recording all the necessary data for events analysis. The joint FERC-NERC event report from the Arizona-Southern California outage of September 2011 highlighted the proliferation of the PMUs which facilitate the event analysis. The PMU has become so ubiquitous because DOE has employed a carrot approach of providing funding for their installation. This approach is much more effective than a penalty approach established in an enforcement regime. (5) In the end, we think the directives issued by FERC in the spring of 2007 have been overcome by six plus years of events. The world has changed tremendously. Furthermore, we believe PRC-018 should be retired rather than developing any standard.
Response: The SDT thanks you for your comment.		
CenterPoint Energy Houston Electric, LLC	No	CenterPoint Energy does not believe there is a need for a new standard at this time. Please see response to Question 4.
Response: The SDT thanks you for your comment.		

Organization	Yes or No	Question 3 Comment
Southern Company Operations Compliance	No	From the GO perspective, post events analysis typically is able to be performed using relay operation records stored within the protective relaying coupled with unit control system historical data. The need for additional high speed data capture equipment, to date, has not been justified from a GO/GOP perspective. The benefit/cost value has not been sufficient to drive the widespread installation of such equipment. The cost for GO/GOP to add DME to each generating facility can be significant due to the design, equipment, and installation costs.
Response: The SDT thanks you for your comment.		
Northeast Power Coordinating Council	No	Once the Standard becomes effective, it will provide continent-wide consistency and clarity for capturing the data needed to analyze various power system disturbances, and validate some of the models used in planning or operational studies. It will decrease the number of standards for this topic. We don't agree with the need for a standard as proposed. There could be a general requirement for providing DME data for events analysis and modeling purposes that could be put in the Rules of Procedure as opposed to a standard.
Response: The SDT thanks you for your comment.		
City of Tallahassee	No	TAL believes the same goal could be accomplished by voluntary efforts.
Response: The SDT thanks you for your comment.		
City of Tallahassee	No	TAL believes the same goal could be accomplished by voluntary efforts.
Response: The SDT thanks you for your comment.		
City of Tallahassee	No	TAL believes the same goal could be accomplished by voluntary efforts.
Response: The SDT thanks you for your comment.		

Organization	Yes or No	Question 3 Comment
Duke Energy	No	The Standard SDT should consider that, as an alternative to a reliability standard, these provisions for collecting and providing data could be made in NERC's Rules of Procedure. As the Commission recognized in Order No. 693 paragraph 1550 approving PRC-018-1, "the procedures specified in PRC-002-1 will be provided pursuant to the data gathering provisions of the ERO's Rules of Procedure and the Commission's ability to obtain information pursuant to section 215 of the FPA and Part 39 of the Commission's regulations".There is precedent for handling this type of data collection activity in the Rules of Procedure. Reliability standards TPL-005-0 and TPL-006-0 likewise dealt with Regional Entity reliability assessments and data to be provided to NERC. In NERC's Oct. 19, 2011 Petition in Docket No. RM12-1 to approve TPL-001-2, NERC requested to withdraw the two pending Reliability Standards: TPL-005-0 "Regional and Interregional Self-Assessment Reliability Reports", and TPL-006-0.1 "Data From the Regional Reliability Organization Needed to Assess Reliability". NERC stated that the requirements from these two Reliability Standards not approved in FERC Order No. 693 have been moved to Sections 803 and 804 of the NERC Rules of Procedure.
Response: The SDT thanks you for your comment.		
MISO	No	We don't agree with the need as proposed. There could be a general requirement for providing DME data for events analysis and modeling purposes. We would suggest the SDT investigate the ability to put this in the Rules of Procedure or as a standing Section 1600 data request as opposed to a standard.
Response: The SDT thanks you for your comment.		
Madison Gas and Electric Company	No	
Dominion Resources Services,	No	

Organization	Yes or No	Question 3 Comment
Inc.		
Ameren	Yes	(1) The SERC Regional Criteria has worked well for SERC and its members. Please consider it as input to your PRC-002-2 development. Each region's present criteria are valid input to the standard. As you are aware the BES topology varies considerably depending on load density, so regional variance and even intra-region differences should be considered.
Response: The SDT thanks you for your comment.		
american Transmission Company, LLC	Yes	ATC believes the standard is necessary to insure consistency of data across the North American Grid.
Response: The SDT thanks you for your comment.		
City of Austin dba Austin Energy	Yes	Austin Energy (AE) supports a standard that increases clarity, especially regarding responsibilities.
Response: The SDT thanks you for your comment.		
Idaho Power Company	Yes	Consistent requirements should assist and facilitate entities with post fault analysis for wide area disturbances and monitoring practices.
Response: The SDT thanks you for your comment.		
FirstEnergy Corp	Yes	FE supports NERC's project to develop a continent-wide standard for disturbance monitoring equipment (DME). Installations of DME devices provide valuable insight for post-event analysis and diagnostics. The DME standard must allow for efficient use of equipment sharing for a TO/GO interface location and not force each owner to separately maintain its own equipment. Additionally, an appropriate balance of required locations must be considered in the reliability cost-benefit.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment.		
Entergy Services, Inc.	Yes	However, the SAR is not clear in that it is not clearly define what “power system” data needs to be collected and why it is important for post event analyses and verification of system models. The specific “Power system” data that would be beneficial needs to be listed along with a justification why the collection of this data is important for improving the reliability of the Bulk Electrical System (BES).
Response: The SDT thanks you for your comment.		
Hydro QuÃ©bec TransÃ‰nergie	Yes	Hydro-QuÃ©bec TransÃ‰nergie supports this initiative as it will bring clarity and consistency in the industry regarding disturbance monitoring while decreasing the number of standards on this topic.
Response: The SDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	ICLP sees this project as an opportunity to correct Issues with PRC-018-1 which we believe serves no reliability purpose. In particular, the existing requirements to perform regular DME maintenance are unnecessarily burdensome - as data recorders are not directly tied to BES real time reliability. We have no problem performing the maintenance, but the record keeping - and the zero compliance approach in the intervals is excessive for a data gathering function.
Response: The SDT thanks you for your comment.		
Independent Electricity System Operator	Yes	Once the standard becomes effective, it will provide similar continent wide conditions for capturing data needed in analyzing various power system disturbances and validating some of the models used in planning or operational studies.
Response: The SDT thanks you for your comment.		

Organization	Yes or No	Question 3 Comment
Essential Power, LLC	Yes	Previously proposed Disturbance Monitoring standards were often vague on who was responsible for requirements and it was difficult for entities to determine exactly the scope of the standard. We see the benefit of this project and encourage the standard SDT to avoid repeating the mistakes of the past.
Response: The SDT thanks you for your comment.		
LG&E and KU Services	Yes	Previously proposed Disturbance Monitoring standards were often vague on who was responsible for requirements, and it was difficult for entities to determine exactly the scope of the standard. We see the benefit of this project and encourage the standard SDT to avoid repeating the mistakes of the past.
Response: The SDT thanks you for your comment.		
ReliabilityFirst	Yes	ReliabilityFirst believes there is definitely a need for this standard. ReliabilityFirst offers the following reasons in support of this standard's development. This proposed standard will improve system reliability by providing personnel with necessary data to enable the industry to more effectively analyze system events that affect the Bulk Electric System and Bulk Power System. The new version of the standard will remove the "fill-in-the-blank" requirements currently assigned to the Regional Reliability Organization within the current PRC-018-1 and PRC-002-1 standards. And finally, with the events data system models can be reviewed and verified for better accuracy. Each of which will enhance overall system reliability.
Response: The SDT thanks you for your comment.		
ITC	Yes	The post 2003 blackout recommendations included the need for synchronized recording devices in power plants and substations to aid in the analysis of wide area events. The industry is faced with a conflict where PRC-002-1 is a fill in the blank standard, thus not FERC approved, but PRC-018-1 is FERC approved. Combining PRC-018-1 into the new PRC-002-2 which will be a continent wide standard is the only

Organization	Yes or No	Question 3 Comment
		way to correct this issue.
Response: The SDT thanks you for your comment.		
South Carolina Electric and Gas	Yes	The standard is needed in order to ensure that sufficient information is collected during a system disturbance to properly evaluate and simulate the disturbance.
Response: The SDT thanks you for your comment.		
Southwest Power Pool	Yes	Utilizing a standard ensures consistency in establishing the requirements for DME across North America. Perhaps some consideration could be given to letting the standard provide overview or generic requirements associated with DME but then the details be provided in a guideline or best practices document. However, given this there may then be a tendency for the regions to add additional details in regional standards which are more in-depth than the NERC standard.
Response: The SDT thanks you for your comment.		
Kansas City Power & Light	Yes	Utilizing a standard ensures consistency in establishing the requirements for DME across North America. Perhaps some consideration could be given to letting the standard provide overview or generic requirements associated with DME but then the details be provided in a guideline or best practices document. However, given this there may then be a tendency for the regions to add additional details in regional standards which are more in-depth than the NERC standard.
Response: The SDT thanks you for your comment.		
Pepco Holdings Inc.	Yes	When determining the selection criteria for where this equipment is to be located, the SDT should be mindful of the significant dollars and resources already expended over the last several years to add DME equipment to specific sites specified by the Regional Reliability Organizations in accordance with PRC-002.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment.		
Exeln and its affiliates	Yes	Yes, however, this standard should be very low burden as a good argument could also be made that a standard is not needed at all. Since the 2003 Blackout, the proliferation of microprocessor relays with ever increasing oscillographic recording and sequence of event recording capabilities has increased the amount of data available to a high level and this increase will continue over time with or without a standard. Many entities, including ComEd, include GPS Satellite clocks in the standard design of their transmission relay schemes, etc. Many entities are voluntarily installing equipment that records and stores synchrophasor data on important generator connections and circuits. This is evidenced by comments by NERC related to investigations of more recent disturbances versus disturbances in the past. We recommend that the only things that need to be in a standard for disturbance monitoring equipment is that a simple list of fault recording equipment needs to be kept, whatever type is used (i.e. relay type (e.g. SEL321), DFR type). Also, a list of long term disturbance monitoring equipment needs to be kept, whatever type is used (long term disturbance monitors or stored phasor data) including that the equipment is connected to a GPS Satellite clocks. Additionally, the standard could require continuous recording for any long term disturbance monitoring, although this is already industry standard, with data retention at least a certain time (e.g. 10 days) and connection of all new monitoring equipment to a GPS Satellite clock. Anything else is just a significant record keeping burden that ComEd does not believe adds anything to reliability and therefore is not justifiable. With modern equipment it is not necessary for NERC to specify things like sample rates, tolerance/accuracy of GPS clocks, etc.
Response: The SDT thanks you for your comment.		
Transmission Reliability Engineering and Controls	Yes	You cannot manage what you do not measure. Much of the data required by this SAR will give utilities better insight into their BES areas.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment.		
Western Area Power Administraton - Upper Great Plains Region	Yes	
Puget Sound Energy	Yes	
Bill Middaugh	Yes	
PacifiCorp	Yes	
Wisconsin Electric Power Company	Yes	
Gustavo Brunello	Yes	
Northeast Utilities	Yes	
Nebraska Public Power District	Yes	
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	

4. **If you do not believe a standard is needed - what other method could be used to achieve the results stated in the revised SAR.**

Summary Consideration:

The SDT appreciates all comments provided and alternatives that have been suggested. The team responds to the common themes in the comments, as follows.

1. The end deliverable of the SAR will be the development of revised NERC standard PRC-002-2. Reasons for this include:

- Some commenters suggested that the standard's purpose could be achieved on a non-mandatory basis, potentially assisted by guidelines or education. The SDT notes that, at the time of the 2003 Northeast Blackout, NERC Planning Committee Standards/Guidelines were in place. Each of the then-10 RROs also had DME requirements for their then-voluntary members to follow. However, the blackout investigations found inadequate DME implemented or operational, with the result that their final reports included the recommendations that are driving the present NERC development effort of PRC-002-2 as a mandatory and enforceable reliability standard.
- Some commenters suggest achieving PRC-002-2's purpose through the NERC RoPs. The SDT notes that:

  If RoP changes are needed, they will be made using the ROP change process (RoP Section 1400), versus the Standard Development Process. The SDT believes the Standard Development Process provides registered entities more influence and control of the development of the reliability requirements that they may become subject to.

  If the RoPs are not changed, data requests will be under RoP Section 1600. A lot more time and process will be required to issue requests per Section 1600 compared to the 10 days request period proposed in PRC-002-2. This may lead to longer recorded data retention periods for registered entities.

  Nothing in current NERC reliability standards or the RoPs compels a registered entity to collect or retain the SOER, FR or DDR data sought by PRC-002-2. RoP Section 1600 can be used to compel an entity to provide data, but only if they already have it or have the means to get it. If an entity did not have SOE, FR or DDR at the time of a system incident or disturbance, the present NERC reliability standards and RoPs could not be used to hold the entity liable for not having the data because they lacked means to record it at the time. Nor could they compel the entity to acquire the means for a potential future incident/disturbance. Inadequate bodies of data to do event analyses could again result.

  RoP violations are enforceable, in the US, only by FERC, versus by Regions or NERC via the ERO CMEP.

If the purpose of PRC-002-2 was to be implemented through the RoPs the SDT anticipates that ROP changes would be required. Also, to effectively meet PRC-002-2's purpose the ROPs would have to somehow implement the same or similar requirements to those that would be in PRC-002-2 as a reliability standard. Compliance would be enforced by FERC. The SDT believes that the purpose of PRC-002-2 should be achieved via development as per the Standards Process Manual, followed by implementation, execution, and compliance monitoring and enforcement of PRC-002-2 as a NERC reliability standard.

2. The SDT anticipates limited ways in which PRC-002-2 could be enforced as a "zero-defect" standard.

- An entity that inadequately implements SOER, FR, or DDR to meet the locational requirements and the (approved) standard implementation plan.
- An entity's data submittal does not meet requirements; e.g.: data synchronization to UTC (+/- 2 ms); timeliness (30 days); data required (currents, voltages, etc).

An entity is not otherwise in violation of the standard in other circumstances. For example, finding DME recording facilities with time synch out more than +/- 2 ms of UTC is not a violation; a violation is only incurred if data is reported with time synch out more than +/- 2 ms of UTC. Also, the DMSDT is not planning to include maintenance requirements from PRC-002-2.

3. When completed, PRC-002-2 will lay out the requirements for SOER, FR and DDR data needed from registered entities. By following the Standard Development Process, this data will be the minimum that industry and other stakeholders accept as required in order to facilitate the event analyses indicated in the standard's Purpose. The SDT does not agree with "grandfathering" of existing facilities that would be inadequate for an entity to meet the reporting obligations it will have under PRC-002-2.

Organization	Yes or No	Question 4 Comment
City of Tallahassee	No	TAL believes voluntary efforts on the part of each entity could be used to provide disturbance monitoring, or an alternative is to leave it up to each region to decide what is needed.
Response: The SDT thanks you for your comment.		
City of Tallahassee	No	TAL believes voluntary efforts on the part of each entity could be used to provide disturbance monitoring, or an alternative is to leave it up to each region to decide

Organization	Yes or No	Question 4 Comment
		what is needed.
Response: The SDT thanks you for your comment.		
City of Tallahassee	No	TAL believes voluntary efforts on the part of each entity could be used to provide disturbance monitoring, or an alternative is to leave it up to each region to decide what is needed.
Response: The SDT thanks you for your comment.		
ACES	No	We believe a guideline that supports the existing events analysis process along with a significant industry educational outreach explaining the benefits of collecting the data would yield better results. Registered entities will pursue projects with reliability benefits if the benefits clearly exist and are well understood. Unfortunately, this standard has the potential to become a zero defect standard that provides little reliability benefit. For example, we can see the proposed synchronization requirement PRC-002 R12 becoming a zero defect requirement that provides little value with paper compliance violations similar to those experienced with PRC-005. Registered entities will be forced to prove they have synchronized equipment because these kinds of maintenance records are easy to misplace and will likely lead to violations of the requirement. Even if they can show the equipment is currently within tolerances, they will have no paperwork showing they synchronized it and will still be in violation even though the end result, synchronized equipment, is the desired result.
Response: The SDT thanks you for your comment.		
PacifiCorp	No	
Dominion Resources Services, Inc.	Yes	Dominion believes the NERC Rules of Procedure can be amended to facilitate analysis of disturbances.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment.		
Southern Company Operations Compliance	Yes	If the information is needed to verify system models, those entities that create and use the models should make the investment to install equipment needed for those studies.
Response: The SDT thanks you for your comment.		
Madison Gas and Electric Company	Yes	The cost associated with a 20% bus implementation could be great for both large and small entities (even though the NSRF believes this is being discussed within the SDT). Perhaps NERC should capture what is currently installed within each interconnection as a starting point prior to new installs or relocation of current devices. The Standard should have a foot note (as in PRC-024-1, foot note 1) that states applicable entities are not required to have DME installed or activated on their assets, or words to that effect. This will allow applicable entities to follow the direction of their RC or PC in where they should place DMEs. It will also allow applicable entities understand the importance of installing DMEs and allow the future budgeting of DME's.
Response: The SDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	We are in favor of having disturbance monitoring equipment (DM) data capture with common capabilities in the field, but we have concerns with the SAR's approach. There could be a general requirement for providing DME data for events analysis and modeling purposes that could be put in the Rules of Procedure as opposed to a standard. We would recommend that the NERC Planning Committee develop a common specification and approach to be used for all North America. If the goal of PRC-002 is to enable a data stream for modeling and disturbance analysis, there should be a single standard for provision of such data or a provision included in the Rules of Procedure.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment.		
Duke Energy	Yes	We do not believe a standard is necessary to accomplish the stated goal. This data collection activity could be handled with appropriate revisions to NERC's Rules of Procedure.
Response: The SDT thanks you for your comment.		
Independent Electricity System Operator	Yes	
Gustavo Brunello	Yes	
Northeast Utilities	Yes	
CenterPoint Energy Houston Electric, LLC		CenterPoint Energy believes there are already regional requirements in place in ERCOT that address many of the items identified in the draft SAR, namely fault and sequence of events data. For example, ERCOT Nodal Operating Guide requirements presently specify the following disturbance monitoring equipment requirements: o Equipment types o Triggering requirements o Location requirements o Data recording requirements o Data retention/reporting requirements (format, elements reported, three-year retention period) o Maintenance requirements o Annual equipment reporting o Review process for DME equipment locationAdditionally, PRC-018-1 already requires entities to follow RRO requirements, and it includes requirements for: o Time sync and data availability o Maintenance program o Data retentionFERC and NERC prepared a report dated April 2012 for the Arizona-Southern California outages of September 2011 indicating that disturbance monitoring data was available in this region for facilitating a quick turnaround of a complex event analysis. Similarly, FERC and NERC prepared a report dated August 2011 for the Southwest cold weather event of February 2011. Furthermore, PRC-004 requires analysis and mitigation of transmission protection system

Organization	Yes or No	Question 4 Comment
		misoperations. Event data assists Entities in recreating the sequence of events needed for cause analysis and mitigation development; therefore, Entities already have un-written requirements to install sufficient recorders to meet PRC-004.
Response: The SDT thanks you for your comment.		
Southwest Power Pool		One way to minimize the oversight of the specification would be for the PC to take an active role is developing the requirements in either the guideline or best practices document which would serve as the source for this type of information.
Response: The SDT thanks you for your comment.		
MISO		We are in favor of having disturbance monitoring equipment (DME) with common capabilities in the field, but we have concerns with the SAR's approach. The SAR proposes to fix a "fill in the blank" problem (where each Region has a specification for DME and a process to collect information) by handing off the responsibility to the Planning Coordinator and Reliability Coordinator. This will exacerbate the problem in that there are more Planning Coordinators (80 according to the NERC Registry) than there are Regions and there is no direct alignment or mapping of transmission owners, transmission planners, generator owners and their respective Planning Coordinator (if they even have one). This will increase the balkanization and add gaps.We would recommend that the NERC Planning Committee develop a common specification and approach to be used for all North America. If the goal of PRC-002 is to enable a data stream for modeling and disturbance analysis, there should be a single standard for provision of such data or a provision included in the Rules of Procedure or a standing Section 1600 data request.

5. **If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:**

Summary Consideration:

The SDT appreciates the comments and has the provided summary responses below:

- *How will the Planning Coordinators and Reliability Coordinators fulfill their obligation?* The PC's and RC's have mandate, experience, and expertise related to assuring reliability of wide areas of the BES. The SDT believes the PC and RC have the wide area perspective necessary to determine BES locations where collection of DDR data would be of the most value for wide area disturbance analysis. *Concern was noted for using MVA short circuit levels for determining DDR locations.* The current draft of PRC-002-2 proposes a short circuit MVA criteria for determination of Sequence of Events and Fault Recording locations not DDR locations.

- *What are the details on the methodology for determining DM locations?* The details for determining the DM recording locations will be included in the standard itself. The details for describing the methodology go beyond the scope of the SAR.

- *How will duplication for DM data collection for GO and TO responsibilities be handled?* The methodology for determining the DM recording location will be designed to avoid the collection of duplicate data.

- *What will happen to Regional Disturbance Monitoring standards?* Regional standards are not in the scope of the SDT. Currently, NPCC is the only region with a FERC approved regional disturbance monitoring standard. The region will decide the status of its Regional Disturbance Monitoring standard.

- *The determination method might be more suitable if it used the FERC 754 data request bus determination method. The FERC 754 method identifies the more strategic elements in the BES.* The FERC Order 754 method refers to the specific steps for the collection of data for the identification of "the buses at which a protection system single point of failure could result in an adverse impact to reliability of the bulk power system." (Quote from NERC's Request for Data or Information Order No. 754 Single Point of Failure on Protection Systems, August 16, 2012, page 7). To ensure complete BES coverage for fault recording, the bus selection screening method to be used has to be more encompassing. The method used will ensure the capturing of BES system wide data.

- *A comment was made concerning grandfathering of the existing equipment.* The team has discussed the option of grandfathering the existing DM equipment that does not meet data quality requirements of the Standard and determined such option would not be justified. The Standard will be applicable to a limited number of locations critical to BES reliability where the specified data quality will be required. Nonetheless, in recognition of the fact that certain existing DME devices with limited capabilities would still provide acceptable data for Disturbance Analysis, the SDT added clauses with relaxed requirements for FR and DDR data quality.

- *Will there be a cost/benefit evaluation, economic impact of the standard?* The NERC Standards Committee has approved the use of a Cost Effectiveness Analysis Process (CEAP) trial application for this project of the Cost Effectiveness Analysis Process (CEAP).

- *Several questions were requirements on equipment maintenance*. The SDT is not planning to specify maintenance requirements.

Organization	Question 5 Comment
Nebraska Public Power District	I have concerns that at stations that have recording equipment already in place that they may not meet the data capabilities required. This may be a significant # of locations for some TOs. Will there be a way to grandfather in existing locations that will be specified in the standard? Some of the statements from the webinar were to use the fault study and then select 20% of buses using the MVA criteria. This kind of analysis seems straight forward but can create complexity with how it is audited by enforcement in order to prove that 20% was achieved. In general does the SDT consider how the standard may be audited? Some aspects of the standard may be difficult to audit so one recommendation is to try and consider if there will be difficulties with auditing as requirements are written.I think that if protective relays are acceptable for performing certain DME functions at certain locations they should not have a maintenance requirement under PRC-002 if they are maintained under PRC-005. The SDT may already agree with this but if not please take this under consideration. PRC-005 is a stringent standard that already aims to make sure relaying is operable for protection which is more critical to the BES then data recording in comparison and it has much longer intervals than quarterly.Many relays could meet the 50 cycles recording length but they are not perfect devices. If a relay does not capture at least 2 cycles of pre trigger and 50 cycles of a fault lasting longer than 50 cycles is this a compliance violation? This requirement is logical but I have concern about compliance and overwriting relay data with extending record length.The need for monitoring tie lines needs to be clear. From the webinar it may not have been.

Organization	Question 5 Comment
Response: The SDT thanks you for your comment.	
Manitoba Hydro	(1) General - de-capitalize the word “standard” throughout the SAR. Alternatively, replace the word “standard” with the words “Reliability Standard”. (2) Need - add a “-” between the words bulk power for consistency with other instances of these words. (3) Objectives and/or Potential Future Metrics - rewrite “BES” as Bulk Electric System (BES) because it is the first instance of these words in the SAR. Also, for clarity, consider adding the words “North American” before Bulk Electric System. (4) Detailed Description - replace Bulk Electric System with its acronym “BES”. (5) General - de-capitalize all instances of “Requirements” because it is not defined in the NERC Glossary of Terms. (6) Detailed Description - capitalize the words “SDT” in the last paragraph in this section for consistency with the rest of the document. (7) OPTIONAL: Technical Analysis Performed to Support Justification - for clarity, “continent” should be referred to as “North American continent”.
Response: The SDT thanks you for your comment.	
Ameren	(1) At present, our Planning Coordinator (MISO) is nearing completion on a 3-year project to install Phasor Measurement Units (PMUs) across the MISO controlled transmission system. These PMUs fall into the category of Dynamic Disturbance Recording (DDR) equipment. It is expected across the industry that this type of equipment will be useful in determining the details of system disturbances. (2) According to the Detailed Description of the SAR, on page 3, “The Planning Coordinators and Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data.” We request clarification on how the Planning Coordinator and Reliability Coordinator will be able to fulfill their obligations of locating this monitoring equipment.(3) In addition, we have concerns that revisions to PRC-002, depending on the specifics of the requirements, could be burdensome to Transmission and Generator Owners who may find they have a vastly increased deployment of this type monitoring equipment in order to be compliant.

Organization	Question 5 Comment
Response: The SDT thanks you for your comment.	
Essential Power, LLC	1. The PRC-002/018 SDT should keep cost justification in mind, especially as regards TO-vs-GO duplication of DME. This project should be included in the CEAP Pilot Program.2. We have been installing this equipment in accordance with our RRO's requirements, but it seems unlikely that anyone will ever ask for data, since the TO has DME on their side of the fence at each plant. The role of GO-collected data in Disturbance analysis may be minimal to nonexistent, in which case it would make sense to require GO's to have DME only under very limited circumstances.3.The revised PRC-002/018 standard should also define the target settings required. The NERC Glossary definition of a Disturbance is of no use, and the criteria in Att. 2 of EOP-004 are written solely for the use of TOs.
Response: The SDT thanks you for your comment.	
LG&E and KU Services	1. The PRC-002-1/PRC-018 SDT should keep cost justification in mind, especially as regards TO-vs-GO duplication of DME. We have been installing this equipment in accordance with our RRO's requirements. However, based on our experience, because TOs have DME on their side of the fence at each plant, the role of GO-collected data in Disturbance analysis may be minimal to nonexistent. Therefore, GOs should be required to have DME only if the applicable TO determines GO DME is necessary.2. This standard may prove difficult for GOs to comply with in terms of disturbance data retrieval because it is dependent upon being aware that a disturbance is occurring somewhere on the transmission system. The GO is not the primary responsible entity for detecting and reporting a disturbance on the BES. On occasion, there may be information about a disturbance that is available to a TO and may not be available to the GO/GOP, therefore, the GO/GOP should not held accountable for the analysis of the disturbance. It should be clear in the standard that the GO/GOP is accountable only for information that is available to them at the time of the disturbance.The revised PRC-002-1/PRC-018-1 standard should also define

Organization	Question 5 Comment
	the target settings for DME.
Response: The SDT thanks you for your comment.	
Hydro QuÃ©bec TransÃ‰nergie	A sentence should be added in the "Need" section to indicate that the Standard SDT will review the need for having a regional Disturbance Monitoring standard (PRC-002-NPCC-01).The location where disturbance monitoring devices will be required must be clearly identified by the SDT using clear equipment description (generating station, unit, bus, lines, transformers...) and clear MVA and/or kV thresholds.In reference to the fourth paragraph of the "Detailed Description" section, consideration should be taken in scenarios where the physical location of the disturbance monitoring equipment is shared between the Generator Operator and the Transmission Operator. Addressing this scenario would prevent duplication of equipment at nearby locations or at the same location.
Response: The SDT thanks you for your comment.	
Northeast Power Coordinating Council	A thoughtful approach must be considered to the possibility of fill-in-the-blank requirements in the standards that apply to the Regional Reliability Organization. Many of these things are no longer done and should be removed from the standards. Some are procedural processes that need not be in the standards, but rather enforced through regional agreements. A few of the items should be codified in the Rules of Procedure. Three phase bolted short circuit MVA thresholds don't appear as appropriate criteria to determine the locations needed to record sufficient power system data for Dynamic Disturbances as stated in SAR (Technical Analysis Performed to Support Justification). Instead of three phase short circuit thresholds, the Planning Coordinator (PC) / Reliability Coordinator (RC) should consider other criteria such as large generation stations with a combined capability above a certain MW level, major load centers, regional and interregional transmission interfaces (flow gates), substations with large tap-changing and phase-shifting transformers, key substations in major load centers. Only Principle number 7 applies. The proposed standard

Organization	Question 5 Comment
	purpose is to collect information to facilitate analysis of a BES disturbance. DDR/DFR do not control, operate, or monitor the BES system. Compliance to this Standard may require Owners to install new equipment. The Implementation Plan when developed should consider the need to budget, engineer, procure and install new DME. Referring to the fourth paragraph of the Detailed Description, it is not appropriate to assign the responsibility of the functional entities. Recommend the fourth paragraph be changed as follows: It is envisioned that the Transmission Owners and Generator Owners will be responsible for the bulk of the Requirements in this Standard and that the Planning Coordinators or Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data. A sentence should be added in the "Need" section to indicate that the Standard SDT will review the need for having a regional Disturbance Monitoring standard (PRC-002-NPCC-01). The location where disturbance monitoring devices will be required must be clearly identified by the SDT using clear equipment description (generating station, unit, bus, lines, transformers…) and clear MVA and/or kV thresholds. In reference to the fourth paragraph of the "Detailed Description" section, consideration should be taken in scenarios where the physical location of the disturbance monitoring equipment is shared between the Generator Operator and the Transmission Operator. Addressing this scenario would prevent duplication of equipment at nearby locations or at the same location.
Response: The SDT thanks you for your comment.	
american Transmission Company, LLC	ATC supports the objective to not specify the required technology.
Response: The SDT thanks you for your comment.	
City of Austin dba Austin Energy	Austin Energy (AE) supports revision of the Disturbance Monitoring standards to close out some “fill-in-the-blank” issues.
Response: The SDT thanks you for your comment.	

Organization	Question 5 Comment
CenterPoint Energy Houston Electric, LLC	CenterPoint Energy believes existing requirements in PRC-018-1 should be reviewed by the team for inclusion in Phase 2 of the Paragraph 81 project, for example, requirements R3 and R5. The VRF for each requirement is “Lower” and the requirements have not been identified as Tier 1, 2, or 3 in the 2013 Actively Monitored List. Furthermore, PRC-018-1 is not a performance-based standard but rather a standard for analytical purposes. This information can be gathered through other existing means, such as NERC Section 400 of the NERC Rules of Procedure.
Response: The SDT thanks you for your comment.	
FirstEnergy Corp	FE is wondering why the reference to a Regional standard is being implied as a relatedstandard in the development of a NERC standard? It is our understanding that the team will begin its work from the draft PRC-002-2 that was started during an informal project development stage. While products from Regional Entity organizations (NPCC, RFC, etc) may be useful for the team's reference, this NERC SDT should not be editing/revising a Regional Entity standard. We suggest the SAR reference to "PRC-002-NPCC-01... Redundant requirements to be removed from this Standard" as found on the top of page 6 be deleted from the SAR. Additionally the "Related Standards" table should be further edited to insert a row for PRC-002-1 with an explanation of "Revise to create PRC-002-2" and edit the explanation statement on PRC-018-1 to say "..after PRC-002-2 approved" for version clarity.
City of Tallahassee	no comment
City of Tallahassee	No comment
Bill Middaugh	No other comments.
Tacoma Power	Tacoma Power appreciates this opportunity to provide comments.
Transmission Reliability Engineering and	The determination method might be more suitable if it used the FERC 754 data

Organization	Question 5 Comment
Controls	request bus determination method. The FERC 754 method identifies the more strategic elements in the BES.
Response: The SDT thanks you for your comment.	
Exeln and its affiliates	The Exelon business units have been using the RFC criteria PRC-002 and have spent time and money to implement the methodology for capturing and reporting data to align with the RFC criteria. The concern is that there are intentions to move away from the Regional Criteria which would cause a reevaluation and possible rework to the methodology currently used.
Response: The SDT thanks you for your comment.	
Public Service Enterprise Group	The need for this standard is driven by recommendations 12A and 12B in the NERC and US-Canada reports on the August 2003 Blackout. The recommendations were made with and in the context of the SOE record produced for and included in the reports. The standard produced via this SAR must improve but be limited to the ability to produce SOE records like those provided in the NERC and US-Canada reports. The standard must be careful not to overshoot with, for instance, requirements designed to acquire data beyond that needed to do SOE records to the extent and granularity included in the NERC and US-Canada blackout reports, which will happen if the standard requires too much data from too many sources (e.g. extensive and unnecessary SOE or FR from small generators or switching stations.
Response: The SDT thanks you for your comment.	
American Electric Power	The proposed standards developed in earlier phases of this project were often vague on stating specifically who was responsible for the requirements. In addition, it was often difficult for entities to determine which devices were in or out of scope. AEP supports the work of this project team, and would encourage them to avoid those earlier missteps as they develop and propose future revisions.

Organization	Question 5 Comment
Response: The SDT thanks you for your comment.	
Entergy Services, Inc.	The purpose section is totally deleted, so the SAR does not contain a proper purpose. The Detailed Description is not clear as to what are the objectives of the standard. Information provided are items that need to be considered when drafting the standard, however there are no clear details as to what objectives are (and their basis) nor the equipment that should be within the scope of the standard (e.g., generating unit size, line voltage, etc.). The SAR is not clear the use of the vague term “power system” in the brief description is unclear. Does “power system” imply the Bulk Power System, Bulk Electric System, or generating equipment?
Response: The SDT thanks you for your comment.	
Wisconsin Electric Power Company	The requirement for generator Dynamic Disturbance Recording (DDR) should be reserved for areas having critical density of generation or load, or for generation near critical flowgates, or for other areas which are recognized as having potential generator stability issues. It should not simply be applied to all generators above a given size. Also for generators, the requirement for DDR should be able to be sufficiently satisfied by using data from plant Distributed Control Systems (DCS).
Response: The SDT thanks you for your comment.	
Independent Electricity System Operator	We advise the SDT to be mindful of the varied system characteristics among different regions and areas. Hence, the standards should not stipulate a one-size fit all type of installation requirements - may that be locational, geographical or voltage based. The locations for installing DMEs, especially the dynamic disturbance recorders, need to consider the relevance, value and type of the recorded data that can contribute to accomplishing the purpose of having useful information for event analysis.
Response: The SDT thanks you for your comment.	

Organization	Question 5 Comment
MISO	We recommend a thoughtful approach to the disposition of requirements in the standards that apply to the Regional Reliability Organization. Many of these things are no longer done and should be removed from the standards. Some are procedural processes that need not be in the standards, but rather enforced through regional agreements. A few of the items should be codified in the Rules of Procedure. If some of requirements have been taken over by Reliability Coordinators, the applicable function in the standard should change. Finally, NERC needs to address who is the Planning Coordinator in an area where none is defined. We also need to realize that if the goal is to eliminate a "fill in the blank" issue, the solution is not to just move the blanks.
Response: The SDT thanks you for your comment.	
Northeast Utilities	We think it is not appropriate to assign under the Detailed Description the responsibility of the functional entities. We recommend the fourth paragraph be changed as follows: "It is envisioned that the Transmission Owners and Generator Owners will be responsible for the bulk of the Requirements in this Standard and that the Planning Coordinators or Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data."
Response: The SDT thanks you for your comment.	
Consolidated Edison Co. of NY, Inc.	We think it is not appropriate to assign under the Detailed Description the responsibility of the functional entities. We recommend the fourth paragraph be changed as follows: "It is envisioned that the Transmission Owners and Generator Owners will be responsible for the bulk of the Requirements in this Standard and that the Planning Coordinators or Reliability Coordinators will be responsible for specifying locations requiring Dynamic Disturbance data."
Response: The SDT thanks you for your comment.	

Organization	Question 5 Comment
Kansas City Power & Light	We would suggest that the SDT give consideration to grandfathering existing Disturbance Monitoring Equipment installations in the new standard. Several entities have invested significant funds in this equipment and some sort of consideration for this equipment is definitely well deserved.The standard needs to clearly specify that any maintenance plans for relays associated with Disturbance Monitoring Equipment would be covered in PRC-005 rather than in PRC-002. Stand-alone Disturbance Monitoring Equipment would be covered in PRC-002. There was additional information that was made available during the webinar held on May 22, 2013 which was beneficial to understanding just where the standard is going. It would have been helpful for all if that information could have been made available earlier in the comment period.
Response: The SDT thanks you for your comment.	
Southwest Power Pool	We would suggest that the SDT give consideration to grandfathering existing DME installations in the new standard. Several entities have invested significant funds in this equipment and some sort of consideration for this equipment is definitely well deserved.The standard needs to clearly specify that any maintenance plans for relays associated with DME would be covered in PRC-005 rather than in PRC-002. Stand-alone DME would be covered in PRC-002.There was additional information that was made available during the webinar held on May 22, 2013 which was beneficial to understanding just where the standard is going. It would have been helpful for all if that information could have been made available earlier in the comment period, especially for those who could not participate in the webinar.
Response: The SDT thanks you for your comment.	
Gustavo Brunello	what is the difference between "Disturbance" and "Event" in the following 2 clauses:R13. Each Transmission Owner and Generator Owner shall have all recorded Sequence of Event, Fault Recording, and DDR data available (locally or remotely) for 10 calendar days after a DisturbanceD_Compliance_ 1.3.1 Each Transmission Owner

Organization	Question 5 Comment
	and Generator Owner shall retain all data provided to the Regional Entity, Reliability Coordinator or NERC for at least three years following the event.
Response: The SDT thanks you for your comment.	

END OF REPORT

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

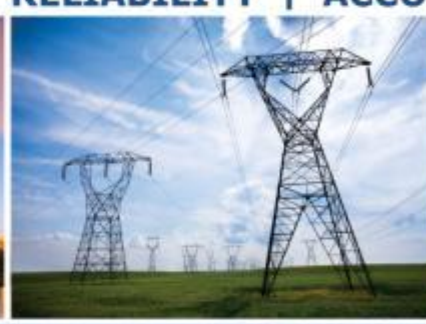
Informal Request for Information

Project 2007-11 Disturbance Monitoring

June 5, 2013

RELIABILITY | ACCOUNTABILITY






3353 Peachtree Road NE
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Introduction and Scope

The NERC Project 2007-11 Disturbance Monitoring Standards Drafting Team (DMSDT) requests specific data as outlined below from Generator Owners and Transmission Owners (in cooperation with their Reliability Coordinators and Planning Coordinators as needed) to enable the Drafting Team to refine the PRC-002-2 Requirements to identify Disturbance Monitoring recording locations. After consideration of comments from the first posting of the Standard in 2009 and further review of the Standard's Requirements, the Drafting Team concluded that using a substation's configuration to determine the locations for Disturbance Monitoring recording would not ensure adequate coverage for Bulk Electric System disturbances. The Drafting Team formed the Monitoring Value Analysis (MVA) Task Team to develop a methodology for determining optimum Disturbance Monitoring recording locations. Using data submitted from several entities, the MVA Task Team realized a correlation existed between three phase fault MVA and optimum Disturbance Monitoring recording siting. PRC-002-2 will require the use of this methodology when locating Disturbance Monitoring recording.

The informal request for information period is open Wednesday, June 5, 2013 through 8 p.m. Eastern Friday, July 4, 2013.

Responses are to be submitted using the Excel spreadsheet. The spreadsheet contains three tabs:

1. DMSDT Information Library
2. Example from NE-USA
3. "Blank" NERC Information Template
    a. Enter your company's information here

Background and Data Requested

Background

Project 2007-11 Disturbance Monitoring is being conducted to establish minimum requirements for capturing power system disturbance data to enable the effective analysis of power system disturbances.

The project impacts two existing standards:

- PRC-002-1 Define Regional Disturbance Monitoring & Reporting Requirements

- PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting

The project involves replacing "fill-in-the-blank" requirements currently assigned to the Regional Reliability Organization with continent-wide requirements that are applicable and would become mandatory to other functional entities, after FERC and the appropriate Provincial Authorities approvals. If necessary, each region can supplement PRC-002-2 with a regional standard or regional criteria that include additional or more stringent requirements.

The DMSDT previously issued a draft standard, and received industry comments, in 2009. The team realized the challenge with establishing continent-wide requirements is the regional variability of the electric grid. The exercise of identifying location thresholds for implementation of Sequence of Events, Fault Recording, and Dynamic Disturbance recording data capture requires an analysis of data from the NERC Regions that identifies appropriate thresholds.

Requested Data

Subject to this request's Information Collection Restraints (see below) and for each Targeted Location (see list below) the following data is requested:

Bolted Three Phase Short Circuit Current and MVA

1. Submit the most up-to-date three phrase short circuit MVA data for a NERC Operating Region.
2. Conditions for the short circuit program should include maximum generation with normal operating connectivity.
3. Provide data for all listed buses at a targeted location (row).

Targeted Locations

The data request is applicable to sites on the electric grid commonly referred to as:

1. Transmission Switching Stations
2. Transmission Substations
3. Generating Stations
4. High Voltage Direct current (HVDC) Converter stations

Data Collection Constraints

1. All buses with three phase short circuit MVA of 1500 MVA or larger should be included.
2. All buses operated at a voltage greater than 100kV L-L.
3. Optional: If an interconnected location has a bus with three phase short circuit MVA less than 1500 MVA, it may be reported for more complete connectivity topology.
4. One bus to be listed per row.

NERC Contact Information

Please return your company's completed Excel spreadsheet via email to Barb Nutter at barbara.nutter@nerc.net **by 8 p.m. Friday, July 5, 2013.**

NERC Points of Contact:
Associate Director - Howard Gugel at howard.gugel@nerc.net
Phone: (609) 651-2269

Standard Developer, Barb Nutter at barbara.nutter@nerc.net
Phone: (404) 446-9692

NERC Information Request - Facilitate Reliability Standard Development

PRC-002-2 – Disturbance Monitoring

Project 2007-11 Disturbance Monitoring (DM)

http://www.nerc.com/pa/Stand/Pages/Project_2007-11_Disturbance_Monitoring.aspx

DMSDT Information Library for Buses: Bus Number, NCR-ID#, Bus kV (L-L), Location, Bus Area, Bus Zone, Bus 3 Phase Fault Current (Amps), and Bus 3 Phase Fault MVA

Information to be provided for buses 100kV (L-L) and higher

		Required		
Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**
TO, TOP, GO coded bus number rather than actual bus number, protected for confidentiality, TO, TOP, GO to keep Bus Coded Number to Actual Bus Number for future reference. **Expected Value: Number**	NERC Compliance Registry ID Number - http://www.nerc.com/pa/comp/Pages/Registration-and-Certification.aspx **Expected Value: Alphanumeric or Text**	Region where bus is located	TO, TOP, GO Bus kV, this is the line to line bus voltage in kV **Expected Value: Number**	TO, TOP, GO Bus 3 Phase fault current, which is the maximum three phase short circuit current at the given bus. This three phase short circuit current is provided in amperes. **Expected Value: Number**

NERC Information Request - Facilitate Reliability Standard Development

PRC-002-2 – Disturbance Monitoring

Project 2007-11 Disturbance Monitoring (DM)

http://www.nerc.com/pa/Stand/Pages/Project_2007-11_Disturbance_Monitoring.aspx

DMSDT Information Library for Buses: Bus Number, NCR-ID#, Bus kV (L-L), Location, Bus Area, Bus Zone, Bus 3 Phase Fault Current (Amps), and Bus 3 Phase Fault MVA

Information to be provided for buses 100kV (L-L) and higher

		Required		
Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**

	A	B	C	D	E	F	G	H
1	**Bus Coded Number**	**NCR-ID #**	**Region**	**Bus kV**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**	**Bus Area -** Optional	**Bus Zone -** Optional
2	0	NCR9999	SERC	345	49188	29393	2	9
3	13987	NCR9999	SERC	345	44994	26886	6	0
4	32	NCR9999	SERC	345	43562	26031	2	8
5	0	NCR9999	SERC	345	38917	23255	8	0
6	0	NCR9999	SERC	345	37962	22684	2	8
7	1320	NCR9999	SERC	345	37646	22496	6	0
8	51399	NCR9999	SERC	345	37406	22352	6	0
9	51398	NCR9999	SERC	345	37376	22334	6	0
10	779	NCR9999	SERC	345	37321	22301	6	0
11	0	NCR9999	SERC	345	36281	21680	6	0
12	13986	NCR9999	SERC	345	34322	20509	6	0
13	0	NCR9999	SERC	345	33348	19927	6	0
14	0	NCR9999	SERC	345	33015	19728	5	6
15	0	NCR9999	SERC	345	32412	19368	5	6
16	13977	NCR9999	SERC	345	32397	19359	6	0
17	804	NCR9999	SERC	345	32112	19188	6	0
18	0	NCR9999	SERC	345	31628	18900	6	0
19	13979	NCR9999	SERC	345	31307	18707	7	0
20	1737	NCR9999	SERC	115	38801	7729	6	0
21	0	NCR9999	SERC	115	38798	7728	9	0
22	0	NCR9999	SERC	115	38798	7728	9	0
23	669	NCR9999	SERC	115	38787	7726	6	0
24	50665	NCR9999	SERC	115	38626	7694	6	0
25	18312	NCR9999	SERC	138	31970	7642	5	704
26	2170	NCR9999	SERC	115	38053	7580	6	0
27	2172	NCR9999	SERC	115	38040	7577	6	0
28	17231	NCR9999	SERC	345	12615	7538	5	704
29	21220	NCR9999	SERC	115	37808	7531	6	0

	A	B	C	D	E	F	G	H
1	**Bus Coded Number**	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**	**Bus Area -** Optional	**Bus Zone -** Optional
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								

FRCC
MRO
NPCC
RFC
SERC
SPP
TRE
WECC

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2007-11 Disturbance Monitoring

Informal Request for Information: June 5, 2013 – July 5, 2013

Now Available

To: Transmission Owners and Generator Owners
Cc: Reliability Coordinators and Planning Coordinators

Informal Request for Information
An informal request for information is open for a 30-day period from Wednesday, June 5, 2013 through 8 p.m. ET on **Friday, July 5, 2013**. **Pleaese note: Response to this informal request for information is not mandatory.**

The Disturbance Monitoring Standard Drafting Team is considering using three phase bolted fault magnitude information to determine the locations for Disturbance Monitoring recording on the Bulk Electric System The location criteria currently under consideration is based on limited information provided by members of the Standard Drafting Team. More information from industry will help to further refine the criteria.

The Disturbance Monitoring Standard Drafting Team is requesting that Transmission Owners and Generator Owners provide bus fault magnitude information for three phase bolted faults on buses operated at 100kV and higher in their areas. The information is to be provided in an electronic format (in an Excel spreadsheet) for the individual buses, and be given as current and the corresponding MVA values. The bus names on the submissions can be changed to preserve confidentiality, but the Standard Drafting Team requests the entity maintain a cross reference to facilitate recording location identification in the event additional information or clarification is needed.

Instructions for Submitting Information
This informal information request to Transmission Owners, Generator Owners, Reliability Coordinators, and Planning Coordinators is **open through 8 p.m. ET on Friday, July 5, 2013**. Please submit your information to Barb Nutter.

If you have any questions about the project or the informal information request, please contact Barb Nutter via email or by telephone at (404) 446.9692.

Next Steps

The timing of the informal request for information will allow for the information provided to be evaluated by the Drafting Team prior to the Workshops on July 30-31, and August 6-7, 2013.

Background information for this project can be found on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Standard Development Timeline

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

Development Steps Completed

1. Nominations for the SAR Drafting Team members were solicited February 26 – March 9, 2007.
2. The SAR was posted for a 30-day comment period March 22 – April 20, 2007.
3. Nominations for the Standard Drafting Team (SDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.
4. The project was placed into informal development the fall of 2010.
5. The project was placed into formal development January 2013.
6. Nominations for two additional SDT members were solicited April 12 – 25, 2013.
7. Three additional SDT members were added May 22, 2013.
8. Industry webinar was held May 22, 2013.
9. Industry technical conferences were held July 30 - 31, 2013 and August 6 - 7, 2013.

Description of Current Draft

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with a 10-day Ballot	November 2013
Final Ballot	May 2014
BOT Adoption	August 2014

Effective Dates

See PRC-002-2 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms (Glossary) used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Dynamic Disturbance Recording (DDR) –The recording of time sequenced data for dynamic power system characteristics such as power swings, frequency variations, and abnormal voltage problems.

Fault Recording (FR) –The recording of time sequenced waveform data for short circuits or failure of Elements resulting in abnormal voltage(s) and/or current(s).

Sequence of Events Recording (SOER) –The recording of time sequenced data for change in status of Elements, which may include protection and control devices.

Rationale for Definitions:

The standard addresses the recording (data), not the equipment used to do the recording. The new definitions in the standard for Dynamic Disturbance Recording (DDR), Fault Recording (FR), and Sequence of Events Recording (SOER) specify the recording, not the devices. The devices were not specified because of the proliferation of multiple function devices, and the intent of the Standard is to address the result, not the how the result was achieved.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.
4. **Applicability:**

Functional Entities:

4.1 The Responsible Entity is:

4.1.1 Eastern Interconnection – Planning Coordinator

4.1.2 ERCOT – Planning Coordinator or Reliability Coordinator

4.1.3 Western Interconnection – Reliability Coordinator

4.2. Transmission Owner

4.3. Generator Owner

Rationale for Functional Entities:

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

Fault Recording (FR) and Sequence of Events Recording (SOER) locations are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these locations. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available at the bus locations established by the Transmission Owner.

B. Requirements and Measures

R1. Each Transmission Owner shall identify BES bus locations for Sequence of Events Recording (SOER) and Fault Recording (FR). *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Bus locations shall be identified using *PRC-002-2 Attachment 1 – Sequence of Events Recording (SOER) and Fault Recording (FR) Locations Selection Methodology*.

1.2. Bus locations shall be assessed at least every five calendar years.

M1. The Transmission Owner has a dated (electronic or hardcopy) list of BES bus locations for Sequence of Events Recording and Fault Recording, identified in accordance with Attachment 1, assessed within the required interval.

Rationale for R1:

SOER and FR data are not required from every location on the BES to conduct adequate analysis of a BES event; SOER and FR from key locations on the BES will suffice. Requirement R1 directs a uniform methodology to select these locations.

Review of actual BES short circuit data received from the industry in response to the DMSDT's June 5, 2013 through July 5, 2013 data request illuminated a strong correlation between the available short circuit MVA at a transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of transmission lines and other devices at the bus, and (iii) the number and size of generating units connected at or near the bus. Buses with a large short circuit MVA level are major contributors to fault currents; these locations have a significant effect on system reliability and performance. Conversely, locations with very low short circuit MVA level seldom cause large system events, so Fault Recording (FR) and Sequence of Events Recording (SOER) typically is not as significant at these locations.

For the purpose of PRC-002-2, a minimum number of locations for FR and SOER are required to facilitate sufficient coverage and data for analyzing large system events. Based on these concepts, the SDT developed a procedure included in Attachment 1 – SOER and FR Locations Selection Methodology, that utilizes the maximum available calculated three phase short circuit MVA. Using this methodology helps ensure sufficient coverage while accounting for variations in size and system strength of Transmission Owners across all the Interconnections. Additionally, this methodology provides flexibility in the selection process.

Each Transmission Owner must re-assess the list of bus locations every five calendar years to account for any system changes such as the addition or removal of large generating resources.

R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the owners of those Elements, within 90 calendar days of determination, that the Elements require Sequence of Events Recording (SOER) and Fault Recording (FR). *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner has dated evidence (electronic or hardcopy) of notification to owners of Elements established in Requirement R1. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R2:

To ensure effective and timely post-event analysis, it is important to have continuity of SOER and FR, with sufficient data from bus locations across the BES. Of the BES bus locations determined in Requirement R1, there may be locations where the Transmission Owner of the bus location does not own all the Elements. This requirement ensures that all necessary BES Elements at a selected bus location have SOER and FR data available by requiring the Transmission Owner of that bus location to notify the other owners of their respective BES Elements that they require SOER and FR per this standard. A 90 calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

R3. Each Transmission Owner and Generator Owner shall have Sequence of Events Recording (SOER) for circuit breaker position (open/close) for each circuit breaker they own connected to the bus locations as per Requirement R2. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M3. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) of Sequence of Events Recording for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings.

Rationale for R3:

Change of state of circuit breaker position, time-stamped, as per Requirement R12 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance.

R4. Each Transmission Owner and Generator Owner shall have Fault Recording (FR) to determine the following electrical quantities at the bus locations as per Requirement R2: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Phase-to-neutral voltages for each phase of either each line or bus.

4.2. Each phase current and the residual or neutral current for the following BES Elements:

4.2.1. Transformers that have a low-side operating voltage of 100kV or above.

4.2.2. Transmission lines.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) of Fault Recording to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

Rationale for R4:

The required electrical quantities may either be directly measured or derived if sufficient data is measured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all phase-to-neutral voltages are required at each location established for either 1) each connected line, or 2) the bus itself. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation.

R5. Each Transmission Owner and Generator Owner shall have Fault Recording (FR) as specified in Requirement R4 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point.
- At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault.

5.2. A minimum recording rate of 16 samples per cycle.

5.3. Trigger settings for at least the following:

5.3.1. Neutral (residual) overcurrent.

5.3.2. Phase undervoltage.

M5. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) that Fault Recording meets Requirement R5. Evidence may include, but is not limited to: (1) device specification (R5, Part 5.2) and configuration (R5, Parts 5.1 and 5.3), or (2) actual data recordings or derivations.

Rationale for R5:

Time-stamped pre- and post-trigger fault data aid in the analysis of protection system operations and determination of operation as designed. System faults generally occur for a short time period, approximately 1 to 50 cycles; thus, a 50 cycle post-trigger minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 50 contiguous cycles post-trigger.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point-on-wave data for recreating accurate fault conditions.

R6. Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which Dynamic Disturbance Recording (DDR) is required. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1. The Elements shall include the following:

6.1.1. A minimum of one DDR location per 3,000 MW of the Responsible Entity's historical peak system Demand, inclusive of Requirement R6, Part 6.1, Sub-parts 6.1.2 – 6.1.7.

6.1.2. At least one DDR location in each Responsible Entity's footprint.

6.1.3. Generating resource(s) with:

6.1.3.1. Gross individual nameplate rating greater than or equal to 500 MVA.

6.1.3.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA.

6.1.4. Locations necessary to monitor all Elements of:

- Eastern Interconnection - all permanent Flowgates.
- ERCOT Interconnection - major transmission interfaces.
- Hydro-Quebec Interconnection - major transmission interfaces.
- Western Interconnection - all major transfer paths as defined by the Regional Entity.

6.1.5. Both ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter.

6.1.6. Locations necessary to monitor all Elements associated with Interconnection Reliability Operating Limits.

6.1.7. Any one Element within a major voltage sensitive area as defined by an in-service undervoltage load shedding (UVLS) program.

6.**2**. The Elements shall be assessed at least every five calendar years.

M6. The Responsible Entity has a dated (electronic or hardcopy) list of BES Elements for Dynamic Disturbance Recording, identified in accordance with Requirement R6, assessed within the required interval.

Rationale for R6:

The Responsible Entity needs to ensure that there are sufficient BES Elements identified for DDR because of the crucial role DDR plays in wide-area disturbance analysis. Additionally, DDR is used for capturing the Bulk Electric System transient and post-transient response and for validating the system model's performance. The requirement for DDR for identified BES Elements, for the purpose of this standard, is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis.

From its experience with changes to the Bulk Electric System that would affect DDR, the SDT decided that the five calendar year re-assessment of the list is a reasonable interval for this review.

R7. Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall notify, within 90 calendar days of determination, each Transmission Owner and Generator Owner of the locations and Elements they own for which Dynamic Disturbance Recording (DDR) is required as established in Requirement R6. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M7. The Responsible Entity has dated evidence (electronic or hardcopy) of notification to owners of Elements established in Requirement R6. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R7:

Communication of selected Elements is required to ensure that the owners of the respective Elements are aware of their responsibilities under this standard. The Responsible Entity is only required to share the list of required Elements that each Transmission Owner and Generator Owner owns.

R8. Each Transmission Owner shall have Dynamic Disturbance Recording (DDR), for each Element they own as per Requirement R7, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1. One phase-to-neutral or positive sequence voltage.

8.2. The phase current on the same phase at the same voltage corresponding to the voltage in Requirement R8, Part 8.1, or the positive sequence current.

8.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

8.4. Frequency of any one of the voltage(s) in Requirement R8, Part 8.1.

M8. The Transmission Owner has evidence (electronic or hardcopy) of Dynamic Disturbance Recording to determine electrical quantities as specified in Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

Rationale for R8:

Dynamic Disturbance Recording is used for measurement of transient response to system disturbances, during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage.

Because all of the buses within a location are at the same frequencies one frequency measurement is adequate.

R9. Each Generator Owner shall have Dynamic Disturbance Recording (DDR), for each Element they own as per Requirement R7, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up (GSU) transformer high-side or low-side voltage level.

9.2. The phase current on the same phase at the same voltage in Requirement R9, Part 9.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

9.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

9.4. Frequency of at least one of the voltages in Requirement R9, Part 9.1.

M9. The Generator Owner has evidence (electronic or hardcopy) of Dynamic Disturbance Recording to determine electrical quantities as specified in Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

Rationale for R9:

A crucial part of wide area disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up (GSU) transformer, measuring the specified electrical quantities, to adequately capture generator response.

R10. Each Transmission Owner and Generator Owner that is responsible for Dynamic Disturbance Recording (DDR) as per Requirement R7 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1. Triggered record lengths of at least three minutes.

10.2. At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set at:
    - No lower than 85% of normal operating voltage for a duration of 5 seconds

M10. Each Transmission Owner and Generator Owner has dated evidence (electronic or hardcopy) of data recording and storage in accordance with Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings.

Rationale for R10:

Large scale system outages generally are an evolving sequence of events that occur over an extended period of time, making DDR an essential component of data collection and event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data are available for the entire Disturbance.

Existing DDR equipment across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

R11. Each Transmission Owner and Generator Owner shall have Dynamic Disturbance Recording (DDR), for the Elements as per Requirement R7, which conform to the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. Input sampling rate of at least 960 samples per second.

11.2. Output recording rate of electrical quantities of at least 30 times per second.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) that Dynamic Disturbance Recording meets Requirement R11. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings (R11, Part 11.2).

Rationale for R11:

Input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle, on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

Output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor low frequency oscillations typically of interest during power system disturbances.

R12. Each Transmission Owner and Generator Owner shall time synchronize all Sequence of Events Recording (SOER), Fault Recording (FR), and Dynamic Disturbance Recording (DDR) data for the bus locations as per Requirement R2 and Elements as per Requirement R7 to within ± 2 milliseconds of Coordinated Universal Time (UTC), time stamped with or without a local time offset. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) of time synchronization described in Requirement R12. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings.

Rationale for R12:

Time synchronization of disturbance monitoring equipment allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of ±2 milliseconds for time synchronization is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

The ±2 milliseconds accuracy requirement specified in this standard is realistically achievable with equipment available and proper cabling installation.

R13. Each Transmission Owner and Generator Owner shall provide Sequence of Event Recording (SOER), Fault Recording (FR), and Dynamic Disturbance Recording (DDR) data for the bus locations as per Requirement R2 and Elements as per Requirement R7 to the Reliability Coordinator, Regional Entity, or NERC upon request: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. The recorded data will be provided within 30 calendar days of a request.

13.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request.

13.3. Sequence of Events Recording data will be provided in Comma Separated Value (.CSV) format following Attachment 2.

13.4. Fault Recording and Dynamic Disturbance Recording data will be provided in electronic C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files.

13.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

M13. The Transmission Owner or Generator Owner has evidence (electronic or hardcopy) data was submitted upon request in accordance with Requirement R13. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records, (2) device specification and configuration, or (3) actual data recordings.

Rationale for R13:

Multiple entities and data recordings may be involved in wide area disturbance analysis therefore, standardized file format and naming conventions improves timely analysis.

The SDT determined that providing the data within 30 calendar days is reasonable based on normal business operations workload. A 10 calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities how long the data will be available.

R14. Each Transmission Owner and Generator Owner, within 90 calendar days of the discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recording (DDR) at the bus locations as per Requirement R2 and Elements as per Requirement R7, shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording ability.
- Report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability.

M14. The Transmission Owner or Generator Owner has dated evidence (electronic or hardcopy) that meets Requirement R14. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, or (3) dated CAP transmittals to the Regional Entity.

Rationale for R14:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures in a reasonable time period to ensure that adequate data is available for event analysis. Therefore, it is required to return the data recording ability to service within 90 calendar days of a discovery of failure. If the Disturbance Monitoring Equipment (DME) equipment cannot be returned to service within 90 calendar days (e.g. budget cycle, service crews, vendors, etc.), the Entity must report it to the Regional Entity along with a Corrective Action Plan for returning the equipment to service.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirements R1 and R2, Measures M1 and M2 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R8, Measure M8 for three calendar years.

The Generator Owner shall retain evidence of Requirement R9, Measure M9 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of Requirements R3, R4, R5, R10, R11, R12, R13, and R14, Measures M3, M4, M5, M10, M11, M12, M13, and M14 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirements R6 and R7, Measures M6 and M7 for five calendar years.

If a Transmission Owner, Generator Owner, or Responsible Entity (Planning Coordinator or Reliability Coordinator) is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 80% but less than 100% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by 30 calendar days or less.	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 70% but less than or equal to 80% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 30 calendar days and less than or equal to 60 calendar days.	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 60% but less than or equal to 70% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 60 calendar days and less than or equal to 90 calendar days.	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for less than or equal to 60% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 90 calendar days.

R2	Long-term Planning	Lower	The Transmission Owner as directed by Requirement R2 was late in notifying the owners by 10 calendar days or less.	The Transmission Owner as directed by Requirement R2 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.	The Transmission Owner as directed by Requirement R2 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.	The Transmission Owner as directed by Requirement R2 was late in notifying one or more owners by greater than 30 calendar days.
R3	Long-term Planning	Lower	Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 75% but less than 100% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.	Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 50% but less than or equal to 75% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.	Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 10% but less than or equal to 50% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.	Each Transmission or Generator Owner as directed by Requirement R3 implemented from 0% but less than or equal to 10% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 75% but less	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 50% but less	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 10% but less	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 0% but less

			than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.	than or equal to 75% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.	than or equal to 50% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.	than or equal to 10% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
R5	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R5.	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 0% but less than or equal to 10% of the total recording properties as specified in Requirement R5.
R6	Long-term Planning	Lower	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 80% but less than 100% of the required Elements. OR	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 70% but less than or equal to 80% of the required Elements.	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 60% but less than or equal to 70% of the required Elements.	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for less than or equal to 60% of the required Elements. OR

			The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by 30 calendar days or less.	OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 30 calendar days and less than or equal to 60 calendar days.	OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 60 calendar days and less than or equal to 90 calendar days.	The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 90 calendar days.
R7	Long-term Planning	Lower	The Responsible Entity as directed by Requirement R7 was late in notifying the owners by 10 calendar days or less.	The Responsible Entity as directed by Requirement R7 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.	The Responsible Entity as directed by Requirement R7 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.	The Responsible Entity as directed by Requirement R7 was late in notifying one or more owners by greater than 30 calendar days.
R8	Long-term Planning	Lower	The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to implement DDR as directed by Requirement R8, Parts 8.1 through 8.4.

R9	Long-term Planning	Lower	The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to implement DDR as directed by Requirement R9, Parts 9.1 through 9.4.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 75% but less than 100% of the Elements they own as determined in Requirement R7.	The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 50% but less than or equal to 75% of the Elements they own as determined in Requirement R7.	The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 0% but less than or equal to 50% of the Elements they own as determined in Requirement R7.	The Transmission Owner or Generator Owner failed to implement continuous or non-continuous DDR, as directed in Requirement R10, for the Elements they own as determined in Requirement R7.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 75% but less than 100% of the total recording properties as	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 50% but less than or equal to 75% of the total recording	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 10% but less than or equal to 50% of the total recording	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 1% but less than or equal to 10% of the total recording

			specified in Requirement R11.	properties as specified in Requirement R11.	properties as specified in Requirement R11.	properties as specified in Requirement R11.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 90% but less than 100% of the bus locations as per Requirements R2 and Elements as per Requirement R7 as directed by Requirement R12.	The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 80% but less than or equal to 90% of the bus locations as per Requirements R2 and Elements as per Requirement R7 as directed by Requirement R12.	The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 70% but less than or equal to 80% of the bus locations as per Requirements R2 and Elements as per Requirement R7 as directed by Requirement R12.	The Transmission Owner or Generator Owner failed to implement time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for less than or equal to 70% of the bus locations as per Requirements R2 and Elements as per Requirement R7 as directed by Requirement R12.

R13	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 30 calendar days but less than 40 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 90% but less than 100% in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 40 calendar days but less than or equal to 50 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 80% but less than or equal to 90% in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 50 calendar days but less than or equal to 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 70% but less than or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 70% but less than or equal to 80% in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 failed to provide the requested data more than 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided less than or equal to 70% in the proper data format.

R14	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days but less than 100 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days but less than or equal to 110 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days but less than or equal to 120 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R14 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111-2013, Measuring relays and protection equipment Part 24: Common format for transient data exchange (COMTRADE) for power systems. Standard published 04/30/2013 by IEEE.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

Attachment 1

Sequence of Events Recording (SOER) and Fault Recording (FR)

Locations Selection Methodology

(Requirement R1)

To identify monitored BES bus locations for Sequence of Events Recording and Fault Recording required by Requirement 1 of PRC-002-2, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES bus locations that it owns.

A single bus location includes any bus Elements at the same voltage level within the same physical location sharing a common ground grid. For example, ring bus or breaker-and-a-half bus configurations are single bus locations.

Step 2. Reduce the list to those locations that have a maximum available calculated three phase short circuit MVA of 1500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES bus locations on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer bus locations, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 bus locations determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20%.

Step 6. Reduce the BES bus locations on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

a. 1500 MVA or

b. 20% of median MVA level determined in Step 5.

Step 7. <u>If there are no bus locations on the list:</u> the procedure is complete and no Fault Recording and Sequence of Events Recording will be required. Proceed to Step 9.

<u>If the list has 11 or fewer bus locations:</u> Fault Recording and Sequence of Events Recording is required at the BES bus location with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9.

<u>If the list has more than 11 bus locations:</u> Fault Recording and Sequence of Events Recording is required on at least the 10% of the BES bus locations, determined in Step 6, with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. Fault Recording and Sequence of Events Recording is required at additional BES bus locations on the list determined in Step 6. The aggregate of the number of bus locations determined in Step 7 and this Step will be at least 20% of the bus locations determined in Step 6.

The additional bus locations are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for Fault Recording and Sequence of Events Recording, therefore the following types of BES locations are recommended:

a. Electrically distant bus locations or from other DME devices.
b. Voltage sensitive areas.
c. Cohesive load and generation zones.
d. Bus locations with a relatively high number of incident transmission circuits.
e. Bus locations with reactive power devices.
f. Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored locations for Sequence of Events Recording and Fault Recording for PRC-002-2 Requirement R1 is the aggregate of the bus locations determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SOER) Data Format

(Requirement R13, Part 13.3)

Date	Time	Local Time Offset from UTC	Substation	Device	State[1]
08/27/13	23:58:57.110	EST	Sub 1	Breaker 1	Close
08/27/13	23:58:57.082	EST	Sub 2	Breaker 2	Close
08/27/13	23:58:47.217	EST	Sub 1	Breaker 1	Open
08/27/13	23:58:47.214	EST	Sub 2	Breaker 2	Open

[1] Acceptable states are either OPEN or CLOSE

Guidelines and Technical Basis

High Level Requirement Overview

Requirement	Entity	Identify Bus Locations	Notification	SOER	FR	5 Year Assessment
R1	TO	X		X	X	X
R2	TO		X	X	X	
R3	TO | GO			X		
R4	TO | GO				X	
R5	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Assessment
R6	RE (PC | RC)	X		X	X
R7	RE (PC | RC)		X	X	
R8	TO			X	
R9	GO			X	
R10	TO | GO			X	
R11	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SOER, FR, DDR Data	SOER, FR, DDR Availability
R12	TO | GO	X		
R13	TO | GO		X	
R14	TO | GO			X

Introduction

The emphasis of PRC-002-2 is not on how Disturbance Monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance Monitoring capability to ensure the completeness of BES data capture.

From a compliance perspective, questions have been raised by industry regarding how conformance to this standard would be judged during a natural disaster which most likely would cause abnormal system conditions for the capturing of data that PRC-002-02 addresses, and also cause the loss of Disturbance Monitoring capability. This is addressed by NERC in its Appendix 4B Sanction Guidelines of the North American Electric Reliability Corporation, Section 2 Basic Principles, Section 2.8 Extenuating Circumstances effective Dec. 20, 2012:

"In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate penalties."

Guideline for Requirement R1:

Sequence of events and fault records for the analysis, reconstruction, and reporting of system disturbances is important. However, SOER and FR data are not required at every location on the BES to conduct adequate or thorough analysis of a disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuit sallow precise reconstruction of events of both localized and wide-area disturbances.

In addition, more quality information is always better than less when performing event analysis. However, 100% coverage of all elements is not practical or required for effective analysis of wide-area disturbance. Therefore, selectivity of required locations to monitor is important for the following reasons:

1. Identify key locations where crucial information is available when required
2. Excessive overlap of coverage is avoided
3. Avoid gaps in critical coverage
4. Provide coverage of system elements that could propagate a disturbance
5. Avoid mandates to cover system elements that are more likely to be a casualty of a disturbance rather than a cause
6. Establish selection criteria to provide effective coverage in different regions of the continent

Listed as follows, the major characteristics available to determine the selection process are:

1. System voltage level
2. The number of transmission lines into a switchyard
3. The number and size of connected generating units

4. The available short circuit levels

Although it is straightforward to establish a bright line criteria for the application of identified locations, analysis was required to establish a sound technical basis to fulfill the required objectives, rather than using opinions, feelings, or anecdotal judgment based upon experience in one area.

To answer these questions and establish criteria for location of SOER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The team collected information from a wide variety of transmission systems throughout the continent to analyze transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SOER and FR coverage, based solely upon simple, bright-line characteristics, as such the number of lines into a switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Location Selection Procedure was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Location Selection Procedure is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent
2. It is likely to select buses near large generation centers
3. It is likely to select buses where delayed clearing can cause electric system cascading outages
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater system impact

To perform the simple calculations of Attachment 1 of the standard, the following information below is required and the following steps (provided in summary form) are required for systems with more than 11 BES bus locations with three-phase short circuit levels above 1500 MVA.

1. Total number of BES buses in the transmission system under evaluation.
   a. Only tangible switchyard buses are included
   b. Pseudo buses created for analysis purposes in system models are excluded
2. Determine the three-phase short-circuit MVA for each bus.
3. Exclude buses from the list with short circuit levels below 1500 MVA
4. Determine the median short circuit for the top 11 buses on the list (position number 6).
5. Multiply median short circuit level by 20%.
6. Reduce the list of BES buses with short circuit levels higher than 20% of the median
7. Apply SOER and FR at buses with short circuit levels in the top 10% of the list (from 6).
8. Apply SOER and FR at buses at an additional 10% of the list using engineering judgment, and allowing flexibility to factor in the following considerations.
   a. Electrically distant bus locations from other DME devices

b. Voltage sensitive areas
c. Cohesive load and generation zones
d. Bus locations with a relatively high number of incident transmission circuits
e. Bus locations with reactive power devices
f. Major facilities interconnecting outside the Transmission Owners' area.

There is no requirement for SOER and FR for generating units in this standard. SOER recordings of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). For event analysis purposes, more valuable information is attained about generators and their response to system events pre- and post-contingency through DDR data versus SOER or FR records.

The reassessment interval of five years was chosen based upon experience. Five years is long enough to avoid unnecessary, but long enough to adapt for changing system configurations.

Guideline for Requirement R2: See rationale.

Guideline for Requirement R3:

Analyses of wide-area disturbances often begin by evaluation of SOERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR recordings, since generator loading can be essentially zero regardless of breaker position. SOER of generator breaker operations provide little useful data of generator loading.

Generator Owners are included in this requirement because a Generator Owner may, in some situations, own breakers at the Transmission Owner's bus location. However, buses owned by the Generator Owner will not require SOER because they will not be studied to begin with. Therefore, only Generator Owners who own equipment at the Transmission Owner location may need to implement SOER per PRC-002-2.

Breaker status can be determined by analysis of suitably time synchronized FRs with the data provided in the manner detailed in R14.

Guideline for Requirement R4:

The bus locations for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The Elements connected to those bus locations for which FR data is required include:

- Transmission lines, including interconnection facilities with generating resources
- Transformers

Only those Elements that are included in BES as per the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100 kV are not included.

Fault recordings are required from each terminal of an Element connected to applicable bus locations.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- The methodology for determining bus locations for (FR) does not include generator buses
- The length of an interconnection between a transmission station and a generating resource is typically short. Current contribution from a generator in case of fault in the transmission system will be captured by fault recording on the transmission station end of the interconnection.
- Faults on the interconnection itself are unlikely. For such faults it is sufficient to have fault current recordings from the transmission station end of the interconnection. Current contribution from a generator is rather deterministic and can be readily calculated if needed.

The SDT, in consultations with NERC's Event Analysis group, determined that DDR from selected generator locations are far more important for event analysis than FRs.

<u>Recording of Electrical Quantities</u>
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FRs it is possible to determine all fault types. Fault Recordings also augment SOERs in evaluating circuit breaker operation.

<u>Current Recordings</u>
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a transmission system is well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$ Equation 1

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's law. Fault currents for one of the Elements connected to a particular bus location can be derived as a vectorial sum of fault currents recorded at the other Elements connected to that bus location.

<u>Voltage Recordings</u>
There are two options for recording phase-to-neutral voltages at applicable bus locations:

1. At terminals of each line. This option would apply to lines that have full set of VTs/CVTs required for distance protections, which is quite common in practice.
2. At a particular bus, in which case all the Elements connected to that common bus are covered. This option may not be applied that often in practice as it requires full set of phase-neutral VTs/CVTs at the bus.

Guideline for Requirement R5:

This requirement directs the applicable entities to have FR at locations determined per Requirement R1 that meets the following:

Requirement R5, Part 5.1 specifies the minimum amount of Fault Recording data. Pre and post trigger fault data along with the SOE breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection system operations after a fault to determine if the protection system operated as designed. Generally speaking, BES faults and the system response to them occur within a very short time period, approximately 1 to 50 cycles, thus a 50 cycle post trigger record length provides adequate data. Multiple records allow for legacy microprocessor relays which when time synchronized to a common clock are capable of providing adequate fault data but not capable of providing fault data in a single record with 50 cycle post trigger data.

Requirement R5, Part 5.2 specifies the minimum recording rate of FR data. A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for SOER.

Requirement R5, Part 5.3 specifies the minimum triggers to ensure FR data is available. A trigger is a set point on an Oscilloscope or Fault Recording device. The trigger can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R5, Part 5.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R5, Part 5.3.2 specifies a phase under-voltage trigger for phase-phase faults.

Guideline for Requirement R6:

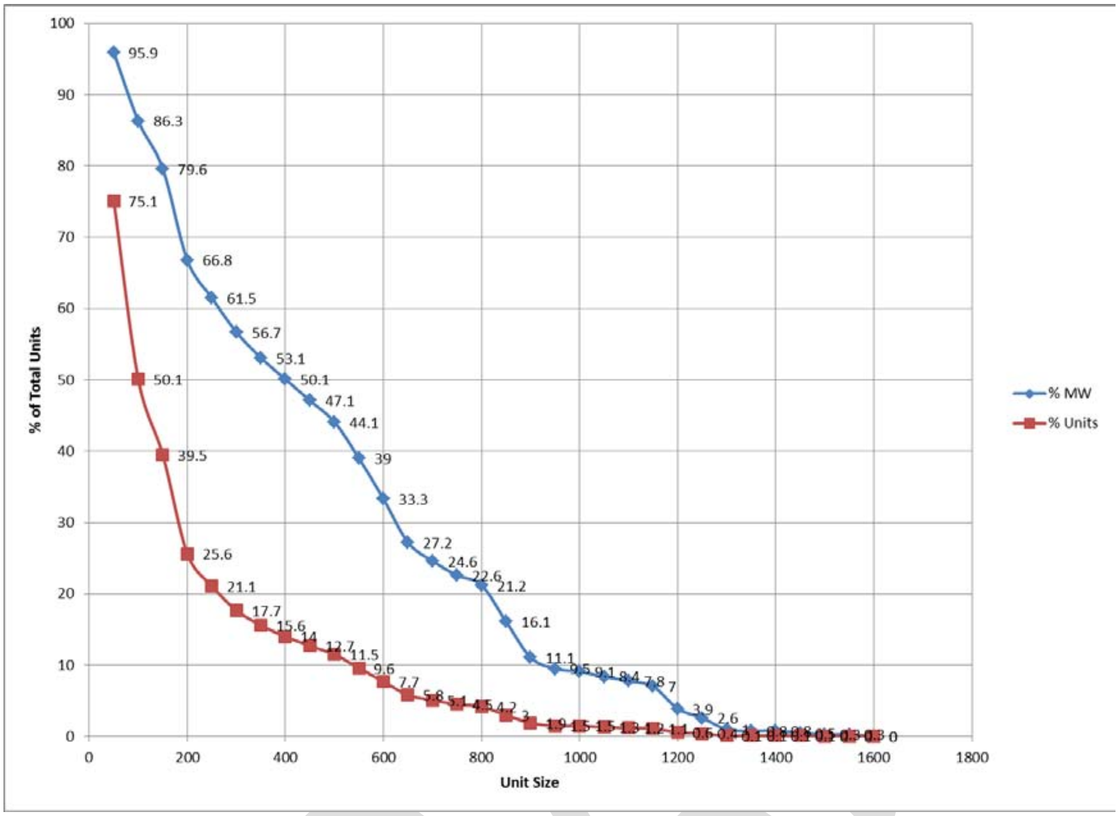
Dynamic Disturbance Recording is used for wide-area disturbance monitoring to determine the system's electromechanical transient and post-transient response and validate system model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the system's dynamic response and ensuring sufficient coverage to determine system performance, DDR is required at key locations in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient locations for DDR coverage for, at a minimum, one location per 3,000 MW of historic peak demand. This number of locations is included to provide adequate system-wide coverage across an Interconnection. To clarify, if any of the key Elements requiring DDR monitoring are within the Responsible Entity's area, these locations are required. If a Responsible Entity (PC or RC) does not have a sufficient number of DDR to meet the one DDR per 3,000 MW of historic peak demand requirement, additional BES Elements must be defined.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a disturbance helps the analysis of large Disturbances. To determine and provide basis for unit size criteria, the DMSDT acquired limited specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which is reporting in 2013 to the NERC GADS program. The team analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The team determined the following basic information about the generating units of interest (current NA fleet i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.
- The information in the spreadsheet does not provide information by which the plant location of each unit can be determined i.e. the team could not use the information to determine which units were located together at a given generation site or facility.

The following figure captures these concepts:



From this information, the team was able to reasonably speculate the generating unit size thresholds proposed in Requirement R6, Part 6.1.3.1 of the standard. The 500MVA individual unit size threshold was selected because this number roughly accounts for 47% of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5% of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R6, Part 6.1.3.2 is included to capture larger units located at large generating plants which could pose a stability risk to the system if multiple large units were lost due to electrical or non-electrical contingencies. The incremental impact to the number of units requiring monitoring is expected to be relatively low.

Major transmission interfaces are explicitly defined based on the Interconnection since a common naming convention for these interfaces does not exist. In the Eastern Interconnection, all Flowgates defined in the NERC Book of Flowgates will require DDR *on the metered end of the Flowgate*. However, this data may be calculated, rather than directly measured, if the accurate quantity can be derived (e.g. either end of the Flowgate line could be monitored since the other end could be derived). In the Western Interconnection, these major transmission interfaces are defined by the Regional Entity. In ERCOT and Quebec Interconnections, the Responsible Entity will be required to identify those interfaces that are deemed significant enough to require monitoring (i.e. are utilized for real-time limits such as System Operating Limits or “contingencies”).

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are areas of significant Load. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective location to monitor DDR such that action of the UVLS or voltage instability could be captured on the BES. For example, a major 500kV or 230kV substation on the EHV system close to the load pocket where the UVLS is deployed would likely be a valuable location for DDR coverage and would aid in post-disturbance analysis of the load area's response to large system deviations (voltage, frequency, etc.).

Guideline for Requirement R7: See rationale.

Guideline for Requirement R8:

Dynamic Disturbance Recording measures transient response to system disturbances after fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of Elements defined by the Responsible Entity (PC or RC) in Requirement R6. Voltage recording is required for all expected bus configurations at a given location. For example, a breaker-and-a-half or double bus configuration has a North (or East) Bus and South (or West) Bus, which would require that both buses should have voltage recording, because either can be taken out of service indefinitely. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either bus voltage transformers to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current record is also acceptable. Duplication of current record is not required, because when a line (or a transformer) is out of service its current and power flow records are nil, and do not impact the event analysis process.

For all circuits where current recording is required, real and reactive power will be recorded on a three-phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R9:

All Guidelines specified for Requirement R8, equally apply to Requirement R9, too. Since either of the high or low side windings of the generator step-up (GSU) transformer may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As it was explained in the Guideline R8, the system (BES) is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Guideline for Requirement R10:

Large scale system outages are generally an evolving sequence of events that occur over an extended period of time, making DDR an essential component of data collection and event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist at some locations that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R10, Part 10.2:

- Off nominal frequency triggers are used to capture high or low frequency excursions of significant size based on the Interconnection size and inertia.
- Rate-of-change of frequency triggers are used to capture major changes in system frequency which could be caused by large changes in generation or load, or possibly changes in system impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recover (FIDVR) events. A sustained voltage of 85% is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R11:

Dynamic Disturbance Recording contains the dynamic response of power system to a disturbance and is used for analyzing complex power system events. This recording is typically used to capture short term and long term disturbances, such as a power swing. Since the data of interest is changing over the time, Dynamic Disturbance Recording is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in a Fault Recording.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency in sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better representation. In the abnormal conditions of interest (e.g. faults or other disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine-generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R12: See rationale.

Guideline for Requirement R13:

This requirement directs the applicable entities that upon requests from the Reliability Coordinator, Regional Entity or NERC to provide SOER, FR data for locations determined in requirement R1 and DDR data for Elements determined per requirement R6. To facilitate the analysis of BES disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R13, Part 13.1 specifies the maximum timeframe of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor.

Requirement R13, Part 13.2 specifies that the minimum time period of 10 calendar days that the data will be retrievable preceding a request. With the equipment in use that has the capability of making a recording, having the data retrievable for the 10 calendar days preceding a request is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days.

Requirement R13, Part 13.3 specifies a Comma Separated Value (.CSV) format per Attachment 2 for the SOER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power system disturbance.

Requirement R13, Part 13.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange it is well established in the industry. It is necessary to specify a standard format as it will be incorporated with other submitted data to provide a detailed analysis of a power system disturbance.

Requirement R13, Part 13.5 specifies the IEEE C37.232 COMNAME format for the naming the data files of the SOER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files first version was approved in 2007. From the August 14, 2003 blackout there was thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and because of that it became difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in their initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of their top ten recommendations.

Guideline for Requirement R14:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the existence of equipment used for SOER, FR, and DDR, at the bus locations which had been established in Requirement R1, which are found to be out of service. The owners are to endeavor to return the equipment to service within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a reasonable amount of equipment out of service does not result in lack of sufficient data for coverage of the system. Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to return the equipment to service within 90 calendar days, the requirement further provides that, for such cases, the entity must report such occasions to the Regional Entity and also provide a Corrective Action Plan. These actions are considered to be the appropriate level of due diligence needed to provide for a robust and adequate data availability.

This Excel Workbook is designed to assist Transmission Owners in using the Median Method for determining monitoring bus locations for Fault Recording and Sequence of Events Recording on their individual systems.

Instructions for use:

For Transmission Owners Only:

1	Organize your short circuit data in the format shown on the Data Input worksheet
2	Your short circuit data should use three phase short circuit with your selected pre-fault voltage
3	Your short circuit data should be ordered from highest three phase short circuit MVA value to lowest three phase short circuit MVA value for all buses greater than 100 kV
4	Your short circuit data should either eliminate or commonly identify non-real buses, zero buses, pseudo buses, or buses which are used for modeling purposes only, by using a common designation for all these type buses that can be eliminated from the Median calculation. It is most common to identify these non-real buses with the number "0" in the bus coded number field.
5	The Data Input Worksheet is designed to have you copy your properly formatted and sorted three phase MVA short circuit data into rows starting at column A row 6 of the worksheet.
6	Data Input, Col. F, is the most important column, it must have the three phase MVA short circuit data values, sorted from highest MVA to lowest MVA. The MVA values in column F, as sorted from highest to lowest MVA, should include all voltage levels greater than or equal to 100 kV.
7	Once you input all of your short circuit data into the Data Input worksheet starting at Column A Row 6, the values in cells B2, B3 and B4 should all be equal. These values should equal the number of rows of short circuit data that you have input. Copy Cell B2 using Cntrl C, then Paste Value, Special value only, back into Cell B2. This should be the total number of rows contained in the data set.
8	If you have zero numbered buses, or pseudo buses, commonly identified by say a number 0 in the bus coded number column, then you need to determine the number of zero numbered buses that are included in this data set.
9	For you to be able to determine this zero bus coded number, you need to select your entire data set, including the header row, from column / row A5 to G___(last row of data). As an example, if your data contains 100 rows, then your highlighted area for sorting and filtering should be A5 to G105. Then using the sort filter command, turn on Filter
10	Once the Filter is on, go to the bus coded number column, pull down the Filter and select only the zero bus coded number rows. The values in cells B3, and B4 should now be equal and indicate the number of zero numbered buses in your data set.
11	We want to store the zero numbered bus rows (number) into cell B4 as a value. To do this, select Cell B4, hit Cntrl C, then hit paste special, value only. This now replaces the formula in Cell B4 with the value of zero buses in the data set.
12	Now we wish to eliminate the zero bus rows from the rest of our data processing, so in the bus coded number column, we want to filter out the zero bus rows, so we reverse the pull down selection by selecting all rows, except the zero bus coded numbered rows. Leave this Filter in place for the rest of the Median method process.
13	If Cell B4 contains the number zero, then Cell F2 should now contain the 6th value down from the highest short circuit MVA value, and Cell G2 should contain 20% of the Cell F2 value. If Cell F2's value is greater than 1500 MVA this is the new lowest MVA value to be used to determine the number of Median selected buses. If the value in F2 is less than 1500 MVA, then we will use 1500 MVA as the lowest value to select the number of Median buses.
14	If Cell B4 contains a value greater than zero, then Cell F2 needs to be replaced with the MVA value contained in the 11th row, column F of the filtered data set. If the value in F2 is less than 1500 MVA then we will use 1500 MVA as the lowest value to select the number of Median buses.
15	With the Filter still applied to our data set, and zero buses deselected, we will need to use the F2 value to apply as the value used for the MVA column pull down.
16	Using Column F, MVA value pull down, use the Number Filter function, greater than or equal to the F2 value. With this Filter F2 number value applied, now Cntrl C Cell C2, and replace C2 with paste special, value only. This now is the number of buses selected by the Median method.
17	You are Finished!!! The number in Cell C2 indicates the number of Median method selected buses, D2 contains the number of total FR and SOER locations, E2 shows the number of FR / SOER for the Top 10% buses and F2 shows the number of FR / SOER for the Distributed 10% buses.
Notes:	Example 1 (Ex 1 without zero buses) is an additional worksheet shown for a system that does not contains any zero buses. All zero bus entries have been eliminated from the data set.
Notes:	Example 2 (Ex 2 with zero buses) is an additional worksheet shown for a system that contains zero buses. Note for a system that contains zero buses, you must observe the row 11, column F MVA value, and place it into Cell F2. In example 2, this MVA value is equal to 5685 MVA, based on the data set provided.

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	0	1	1	0	0	1500
Median Method	0	1	1	0		1500
Zero Busses	0	0	0	0		
Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**	

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	96	20	10	10	5685	1500
Median Method	64	13	7	6		1500
Zero Busses	0	0	0	0		

Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**
19	NCR ID#	FRCC	230	31120	12397
319	NCR ID#	FRCC	230	23087	9197
52	NCR ID#	FRCC	230	17615	7017
58	NCR ID#	FRCC	230	17039	6788
56	NCR ID#	FRCC	230	16472	6562
23	NCR ID#	FRCC	230	14271	5685
31	NCR ID#	FRCC	230	14018	5584
295	NCR ID#	FRCC	115	27868	5551
294	NCR ID#	FRCC	115	27828	5543
315	NCR ID#	FRCC	230	13810	5502
312	NCR ID#	FRCC	230	12018	4788
51	NCR ID#	FRCC	230	10785	4296
316	NCR ID#	FRCC	230	10616	4229
314	NCR ID#	FRCC	230	10558	4206
320	NCR ID#	FRCC	230	10552	4204
53	NCR ID#	FRCC	230	10342	4120
317	NCR ID#	FRCC	230	10279	4095
302	NCR ID#	FRCC	230	10103	4025
55	NCR ID#	FRCC	230	10076	4014
59	NCR ID#	FRCC	230	9713	3869
304	NCR ID#	FRCC	230	9618	3831
60	NCR ID#	FRCC	230	9605	3826
299	NCR ID#	FRCC	230	9598	3823
303	NCR ID#	FRCC	230	9542	3801
54	NCR ID#	FRCC	230	9110	3629
231	NCR ID#	FRCC	115	14835	2955
215	NCR ID#	FRCC	115	14296	2848
269	NCR ID#	FRCC	115	13212	2632
309	NCR ID#	FRCC	115	12895	2568
230	NCR ID#	FRCC	115	12889	2567
301	NCR ID#	FRCC	115	12781	2546
266	NCR ID#	FRCC	115	12723	2534
238	NCR ID#	FRCC	115	12674	2525
260	NCR ID#	FRCC	115	12674	2525
306	NCR ID#	FRCC	115	11990	2388

271	NCR ID#	FRCC	115	11826	2356
249	NCR ID#	FRCC	115	11049	2201
247	NCR ID#	FRCC	115	10975	2186
246	NCR ID#	FRCC	115	10902	2171
313	NCR ID#	FRCC	115	10868	2165
262	NCR ID#	FRCC	115	10472	2086
242	NCR ID#	FRCC	115	10243	2040
228	NCR ID#	FRCC	115	10089	2010
248	NCR ID#	FRCC	115	9865	1965
217	NCR ID#	FRCC	115	9560	1904
297	NCR ID#	FRCC	115	9521	1896
209	NCR ID#	FRCC	115	9295	1851
243	NCR ID#	FRCC	115	8969	1787
218	NCR ID#	FRCC	115	8926	1778
265	NCR ID#	FRCC	115	8913	1775
232	NCR ID#	FRCC	115	8882	1769
210	NCR ID#	FRCC	115	8875	1768
240	NCR ID#	FRCC	115	8538	1701
239	NCR ID#	FRCC	115	8442	1681
307	NCR ID#	FRCC	115	8397	1673
270	NCR ID#	FRCC	115	8349	1663
272	NCR ID#	FRCC	115	8193	1632
258	NCR ID#	FRCC	115	8000	1593
310	NCR ID#	FRCC	115	7891	1572
211	NCR ID#	FRCC	115	7837	1561
261	NCR ID#	FRCC	115	7822	1558
225	NCR ID#	FRCC	115	7730	1540
234	NCR ID#	FRCC	115	7557	1505
233	NCR ID#	FRCC	115	7543	1502
204	NCR ID#	FRCC	115	7386	1471
259	NCR ID#	FRCC	115	7374	1469
256	NCR ID#	FRCC	115	7314	1457
298	NCR ID#	FRCC	115	7258	1446
244	NCR ID#	FRCC	115	7249	1444
222	NCR ID#	FRCC	115	7204	1435
223	NCR ID#	FRCC	115	7133	1421
263	NCR ID#	FRCC	115	7118	1418
226	NCR ID#	FRCC	115	6989	1392
254	NCR ID#	FRCC	115	6913	1377
267	NCR ID#	FRCC	115	6851	1365
257	NCR ID#	FRCC	115	6846	1364
253	NCR ID#	FRCC	115	6772	1349
245	NCR ID#	FRCC	115	6704	1335
308	NCR ID#	FRCC	115	6571	1309
251	NCR ID#	FRCC	115	6473	1289
241	NCR ID#	FRCC	115	6395	1274
252	NCR ID#	FRCC	115	5556	1107

255	NCR ID#	FRCC	115	5007	997
5	NCR ID#	FRCC	13.2	39503	903
9	NCR ID#	FRCC	13.2	39501	903
13	NCR ID#	FRCC	13.2	39501	903
1	NCR ID#	FRCC	13.2	39492	903
17	NCR ID#	FRCC	13.2	39473	902
6	NCR ID#	FRCC	13.2	39306	899
10	NCR ID#	FRCC	13.2	39304	899
14	NCR ID#	FRCC	13.2	39304	899
2	NCR ID#	FRCC	13.2	39295	898
18	NCR ID#	FRCC	13.2	39276	898
214	NCR ID#	FRCC	115	4498	896
250	NCR ID#	FRCC	115	4329	862
318	NCR ID#	FRCC	13.2	13238	303

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	120	24	12	12	5685	1500
Median Method	64	13	7	6		1500
Zero Busses	24	5	3	2		
Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**	
19	NCR ID#	FRCC	230	31120	12397	
319	NCR ID#	FRCC	230	23087	9197	
52	NCR ID#	FRCC	230	17615	7017	
58	NCR ID#	FRCC	230	17039	6788	
56	NCR ID#	FRCC	230	16472	6562	
23	NCR ID#	FRCC	230	14271	**5685**	
31	NCR ID#	FRCC	230	14018	5584	
295	NCR ID#	FRCC	115	27868	5551	
294	NCR ID#	FRCC	115	27828	5543	
315	NCR ID#	FRCC	230	13810	5502	
312	NCR ID#	FRCC	230	12018	4788	
51	NCR ID#	FRCC	230	10785	4296	
316	NCR ID#	FRCC	230	10616	4229	
314	NCR ID#	FRCC	230	10558	4206	
320	NCR ID#	FRCC	230	10552	4204	
53	NCR ID#	FRCC	230	10342	4120	
317	NCR ID#	FRCC	230	10279	4095	
302	NCR ID#	FRCC	230	10103	4025	
55	NCR ID#	FRCC	230	10076	4014	
59	NCR ID#	FRCC	230	9713	3869	
304	NCR ID#	FRCC	230	9618	3831	
60	NCR ID#	FRCC	230	9605	3826	
299	NCR ID#	FRCC	230	9598	3823	
303	NCR ID#	FRCC	230	9542	3801	
54	NCR ID#	FRCC	230	9110	3629	
231	NCR ID#	FRCC	115	14835	2955	
215	NCR ID#	FRCC	115	14296	2848	
269	NCR ID#	FRCC	115	13212	2632	
309	NCR ID#	FRCC	115	12895	2568	
230	NCR ID#	FRCC	115	12889	2567	
301	NCR ID#	FRCC	115	12781	2546	
266	NCR ID#	FRCC	115	12723	2534	
260	NCR ID#	FRCC	115	12674	2525	
238	NCR ID#	FRCC	115	12674	2525	
306	NCR ID#	FRCC	115	11990	2388	
271	NCR ID#	FRCC	115	11826	2356	

249	NCR ID#	FRCC	115	11049	2201
247	NCR ID#	FRCC	115	10975	2186
246	NCR ID#	FRCC	115	10902	2171
313	NCR ID#	FRCC	115	10868	2165
262	NCR ID#	FRCC	115	10472	2086
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217	NCR ID#	FRCC	115	9560	1904
297	NCR ID#	FRCC	115	9521	1896
209	NCR ID#	FRCC	115	9295	1851
243	NCR ID#	FRCC	115	8969	1787
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265	NCR ID#	FRCC	115	8913	1775
232	NCR ID#	FRCC	115	8882	1769
210	NCR ID#	FRCC	115	8875	1768
240	NCR ID#	FRCC	115	8538	1701
239	NCR ID#	FRCC	115	8442	1681
307	NCR ID#	FRCC	115	8397	1673
270	NCR ID#	FRCC	115	8349	1663
272	NCR ID#	FRCC	115	8193	1632
258	NCR ID#	FRCC	115	8000	1593
310	NCR ID#	FRCC	115	7891	1572
211	NCR ID#	FRCC	115	7837	1561
261	NCR ID#	FRCC	115	7822	1558
225	NCR ID#	FRCC	115	7730	1540
234	NCR ID#	FRCC	115	7557	1505
233	NCR ID#	FRCC	115	7543	1502

Implementation Plan

Project 2007-11 Disturbance Monitoring

Requested Approvals

- PRC-002-2 Disturbance Monitoring and Reporting Requirements

Requested Retirements

- PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements
- PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting

Prerequisite Approvals

- None

Applicable Entities

- Planning Coordinator
- Reliability Coordinator
- Transmission Owner
- Generator Owner

Revisions to Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definitions:	
Dynamic Disturbance Recording (DDR)	The recording of time sequenced data for dynamic power system characteristics such as power swings, frequency variations, and abnormal voltage problems.
Fault Recording (FR)	The recording of time sequenced waveform data for short circuits or failure of Elements resulting in abnormal voltage(s) and /or current(s).
Sequence of Events Recording (SOER)	The recording of time sequenced data for change in status of Elements, which may include protection and control devices.

Background

The Implementation Plan reflects consideration of the following:

1. This standard reflects the need for data, rather than equipment, with the understanding that the data is collected from Disturbance Monitoring Equipment distributed across the system.
2. A significant amount of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording equipment already exists on the BES. The location requirements in this standard align with industry practices for locating this equipment. Therefore, many existing recordings can satisfy the Requirements and Implementation Plan put forth.
3. Fault MVA data is readily available or calculable by the Transmission Owners for the bus locations they own. Therefore, six (6) months is adequate time for generating the list of BES bus locations following the methodology described in Attachment 1.
4. Responsible Entities have the relevant data and information pertaining to the Elements requiring Dynamic Disturbance Recording and six (6) months is adequate time for working with any affected Entities and generating the list of Elements.
5. The nine (9) month time period for R2, R7, and R14 includes the six (6) month implementation for R1, and R6 (refer to 3, and 4 preceding), and a three (3) month additional time period to make notifications. The nine (9) months for R14 implementation is reasonable for the contents of that requirement. All requirements pertaining to possible implementation of equipment are referenced to notification of the list of bus locations or Elements to account for any delays in the process of location and Element selection.
6. A total percentage (%) of BES bus locations and Elements established in Requirements R1 and R6 respectively, are used in the Implementation Plan since these lists are explicitly created and readily available. It is expected that many locations will become compliant with incremental changes to recording.
7. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the Entities. The timelines put forth allow for inertial delays in implementing new equipment or technologies (e.g. developing new standards and processes, testing and energization, and project management).
8. Implementation of disturbance monitoring following changes to the system are addressed by referencing the Implementation Plan to the time of notification following reassessment. Changes to disturbance monitoring are only required for identified bus locations or Elements following reassessment of the lists as per Requirement R1, Part 1.2 and Requirement R6, Part 6.2.

9. Implementing SOER, FR, and DDR may require scheduled outages for both Transmission Owners and Generator Owners. Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant. Meanwhile, Transmission Owners will have more Elements requiring SOER, FR, and DDR and may have to schedule outages across the system. The Implementation Plan takes this into account for scheduling outages.
10. An Entity owning only one (1) identified bus location, Element, or generating unit is allowed four (4) years for implementation to accommodate normal outage schedules.
11. The Implementation Plan accounts for any increase in requests to vendors for this technology or equipment that could impact implementation timelines for the respective Entities.

General Considerations

Each Transmission Owner and Generator Owner shall maintain the ability to provide Disturbance data using current methods until the entity meets the requirements of PRC-002-2 in accordance with this Implementation plan. As required in PRC-018-1 Disturbance Monitoring Equipment Installed and Data Reporting, Requirement R1, Parts 1.1 and 1.2, it is expected that the Transmission Owner and Generator Owner will have those functionalities in regards to their current Disturbance Data.

Standard(s) for Retirement

PRC-002-1	Midnight of the day immediately prior to the Effective Date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.
PRC-018-1	Midnight of the day immediately prior to the Effective Date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for Definitions

Entities shall use these definitions when implementing any requirement in this standard that references one of the definitions.

Implementation Plan for PRC-002-2 Requirements R1 and R6:

Entities shall be 100% compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R7, and R14:

Entities shall be 100% compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13:

Entities shall be compliant with the initial list of BES bus locations in Requirement R1 and list of Elements in Requirement R6 within the following:

- Following governmental authority or as otherwise provided for in jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect,
  - At least 25% compliant within two (2) years following notification of the list
  - At least 50% compliant within three (3) years following notification of the list
  - 100% compliant within four (4) years following notification of the list

  - **Note**: Entities that own only one (1) identified BES bus location, Element, or generating unit shall be 100% compliant within four (4) years following notification of the list.

- Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is forty-eight (48) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction,

Entities shall be 100% compliant with a reassessed list from Requirement R1, Part 1.2 or R6, Part 6.2 within three (3) years following notification of the list.

Implementation Plan Summary											
Requirement	Entity	Identify bus locations/ Elements	Notification	SOE	FR	DDR	Time Sync	5 Year Assessment	Other	Percent Compliant	Following compliance instructions noted for each requirement above:
R1	TO	X		X	X			X		100	Six (6) months
R2	TO		X							100	Nine (9) months
R3	TO/GO			X						25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R4	TO/GO				X					25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R5	TO/GO				X					25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R6	RE (PC or RC)	X				X		X		100	Six (6) months
R7	RE (PC or RC)		X							100	Nine (9) months
R8	RE (PC or RC)					X				25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R9	TO					X				25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R10	GO					X				25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R11	TO/GO					X				25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R12	TO/GO						X			25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R13	TO/GO								X	25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R14	TO/GO								X	100	Nine (9) months

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Unofficial Comment Form

Project 2007-11 Disturbance Monitoring

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard Authorization Request (SAR). The electronic comment form must be completed by 8 p.m. Eastern on **December 16, 2013**.

If you have questions please contact Barb Nutter via email or by telephone at 404-446-9692.

Click here for the Project Page.

Background Information

Project 2007-11 Disturbance Monitoring was initiated to replace the existing fill-in-the-blank Standard PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements with a more comprehensive standard. (Fill-in-the-blank standards are those standards that depend on regional criteria or procedures not currently contained within certain Reliability Standards, but which are needed to provide additional requirements for implementing the standards within the Regions.)

In its Order 693 (March 16, 2007) FERC did not approve or remand PRC-002-1 "…because the regional requirements for installing Disturbance Monitoring Equipment had not been submitted." FERC, in Order 693 did approve PRC-018-1. Similar to PRC-002-1, PRC-018-1 contained Regional Reliability Organization (the term Regional Reliability Organization used in PRC-018-1, now Regional Entity) requirements. FERC stated that PRC-018-1 ensured "that disturbance monitoring equipment is installed and disturbance data is reported in accordance with comprehensive requirements." Project 2007-11 was moved to informal development in the Fall of 2010. The Project was restored to formal development status in January, 2013.

The Purpose of PRC-002-2 is "To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances." For Sequence of Events and Fault Recording, the Drafting Team decided that it was more practical to require recording, not require equipment, to capture adequate information to analyze BES disturbances. An entity must have data recorded that could determine abnormal disturbance values at a location. It is not the "how", but the "what" regarding data capture. The Drafting Team set up a Monitored Value Analysis Team that looked at three phase bolted bus short circuit MVA data received from members of the Drafting Teams. The Team determined that as long as data was captured for analysis from buses, the Bulk Electric System response to a disturbance could be determined. An Informal Request for Information was posted to industry from June 5, 2013 through July 5, 2013 for short circuit data from around the continent. The information received confirmed the team's analysis. The Drafting Team developed a Locations Selection Methodology which is Attachment 1 in PRC-002-2.

For Dynamic Disturbance Recording, Requirements define the locations Dynamic Disturbance Recording data must be captured for.

The Drafting Team developed three new definitions that are used and included in the posted PRC-002-2: Dynamic Disturbance Recording (DDR), Fault Recording (FR), Sequence of Events Recording (SOER) These definitions will be added to the NERC Glossary of Terms Used in Reliability Standards.

Transmission Owners and Generator Owners will be responsible for the majority of the Requirements in PRC-002-2. Responsible Entities include Planning Coordinators and Reliability Coordinators, as applicable. Each Responsible Entity will be responsible to identify BES Elements for Dynamic Disturbance Recording.

This Project will replace PRC-002-1 with PRC-002-2, and allow the retirement of PRC-018-1.

Transmission Owners – Please note the following:

Requirement R1 requires each Transmission Owner to identify BES bus locations for Sequence of Events Recording (SOER) and Fault Recording (FR). The bus locations are identified using *PRC-002-2 Attachment 1 – Sequence of Events Recording (SOER) and Fault Recording (FR) Locations Selection Methodology*.

An Excel Workbook has been designed to assist Transmission Owners in using the methodology (referred to as the Median Method) discussed in Attachment 1. This workbook has been posted along with the other PRC-002-2 materials during this comment period to give Transmission Owners the opportunity to try out Requirement R1's bus location method by either using their entire system data, or a selected portion of their systems to obtain a full or partial listing of the bus locations that would have to be included in for SOER and FR.

**Please use the electronic comment form to submit your final comments to NERC.*

You do not have to answer all questions. Enter All Comments in Simple Text Format.
Bullets, numbers, and special formatting will not be retained. Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

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

☐ Yes
☐ No

Comments:

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

☐ Yes
☐ No
Comments:

3. Are the appropriate functional entities identified in the Applicability section for PRC-002-2?
☐ Yes
☐ No
Comments:

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

☐ Yes
☐ No
Comments:

5. Do you agree with the VRFs/VSLs and the Drafting Team's justification? If not, please explain why.
☐ Yes
☐ No
Comments:

6. Do you agree with the Implementation Plan? If not, please explain why.
☐ Yes
☐ No
Comments:

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

A. Introduction

1. **Title:** **Define Regional Disturbance Monitoring and Reporting Requirements**

2. **Number:** PRC-002-1

3. **Purpose:** Ensure that Regional Reliability Organizations establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of Disturbance data to facilitate analyses of events and verify system models.

4. **Applicability**

   4.1. Regional Reliability Organization.

5. **Effective Date:** Nine months after BOT adoption.

B. Requirements

R1. The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:

R1.1. Location, monitoring and recording requirements, including the following:

R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R1.1.2. Devices to be monitored.

R2. The Regional Reliability Organization shall establish the following installation requirements for fault recording:

R2.1. Location, monitoring and recording requirements, including the following:

R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R2.1.2. Elements to be monitored at each location.

R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R2.1.3.1. Three phase to neutral voltages.

R2.1.3.2. Three phase currents and neutral currents.

R2.1.3.3. Polarizing currents and voltages, if used.

R2.1.3.4. Frequency.

R2.1.3.5. Megawatts and megavars.

R2.2. Technical requirements, including the following:

R2.2.1. Recording duration requirements.

R2.2.2. Minimum sampling rate of 16 samples per cycle.

R2.2.3. Event triggering requirements.

R3. The Regional Reliability Organization shall establish the following installation requirements for dynamic Disturbance recording:

R3.1. Location, monitoring and recording requirements including the following:

R3.1.1. Criteria for equipment location giving consideration to the following:

- Site(s) in or near major load centers
- Site(s) in or near major generation clusters
- Site(s) in or near major voltage sensitive areas
- Site(s) on both sides of major transmission interfaces
- A major transmission junction
- Elements associated with Interconnection Reliability Operating Limits
- Major EHV interconnections between control areas
- Coordination with neighboring regions within the interconnection

R3.1.2. Elements and number of phases to be monitored at each location.

R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R3.1.3.1. Voltage, current and frequency.

R3.1.3.2. Megawatts and megavars.

R3.2. Technical requirements, including the following:

R3.2.1. Capability for continuous recording for devices installed after January 1, 2009.

R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.

R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following:

R4.1. Criteria for events that require the collection of data from DMEs.

R4.2. List of entities that must be provided with recorded Disturbance data.

R4.3. Timetable for response to data request.

R4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE[1] analysis tool,

R4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files[2].

R4.6. Data content requirements and guidelines.

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[1] IEEE C37.111-1999 IEEE Standard Common Format for Transient Data Exchange for Power Systems or its successor standard

[2] Compliance with this requirement is not effective until the IEEE Standard is approved.

R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.

R6. The Regional Reliability Organization shall periodically (at least every five years) review, update and approve its Regional requirements for Disturbance monitoring and reporting.

C. Measures

M1. The Regional Reliability Organization's requirements for the installation of Disturbance Monitoring Equipment shall address Requirements 1 through 3.

M2. The Regional Reliability Organization's Disturbance monitoring data reporting requirements shall include all elements identified in Requirements 4.

M3. The Regional Reliability Organization shall have evidence it provided its Regional Disturbance monitoring and reporting requirements as required in Requirement 5.

M4. The Regional Reliability Organization shall have evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its DME requirements for three years.

The Compliance Monitor will retain its audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through providing its documentation of Disturbance Monitoring and Reporting requirements or self-certification as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exist:

2.1.1 Disturbance data reporting requirements were not specified as required in R4.1 through R4.6.

2.1.2 No evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in R6.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions exist:

2.2.1 Technical requirements were not specified for one or more types of DMEs.

2.2.2 Requirements do not provide criteria for equipment location or criteria for monitored elements or monitored quantities as required R1, R2 and R3.

2.3. Level 3: Not applicable.

2.4. Level 4: Disturbance monitoring and reporting requirements were not available or were not provided to Transmission Owners and Generator Owners.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Disturbance Monitoring Equipment Installation and Data Reporting**

2. **Number:** PRC-018-1

3. **Purpose:** Ensure that Disturbance Monitoring Equipment (DME) is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

5. **Effective Dates:** Phased in over four years after BOT adoption:

   Requirements 1 and 2:

   – 50% compliant two years after initial issuance of regional requirements per RELIABILITY STANDARD PRC-002 Requirement 5.

   – 75% compliant three years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   – 100% compliant four years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   Requirements 3 through 6:

   – 100% compliant six months after BOT adoption for already installed DME.

   – 100% compliant six months after installation for DMEs installed to meet Regional Reliability Organization requirements per reliability standard PRC-002 Requirements 1, 2 and 3.

B. Requirements

R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:

R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)

R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days..

R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization’s installation requirements (reliability standard PRC-002 Requirements 1 through 3).

R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region’s installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):

R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).

R3.2. Make and model of equipment.

R3.3. Installation location.

R3.4. Operational status.

R3.5. Date last tested.

R3.6. Monitored elements, such as transmission circuit, bus section, etc.

R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc.

R3.8. Monitored electrical quantities, such as voltage, current, etc.

R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).

R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.

R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:

R6.1. Maintenance and testing intervals and their basis.

R6.2. Summary of maintenance and testing procedures.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have evidence that DMEs it is required to have meet the functional requirements specified in Requirement 1 and are installed in accordance with its associated Regional Reliability Organization's requirements (R2).

M2. The Transmission Owner and Generator Owner shall each maintain the data listed in Requirements 3.1 through 3.8 for the DMEs installed to meet its Regional Reliability Organization's DME installation requirements.

M2.1 The Transmission Owner and Generator Owner shall each have evidence it provided this DME data to its Regional Reliability Organization within 30 calendar days of a request.

M3. The Transmission Owner and Generator Owner shall each have evidence it retained and provided recorded Disturbance data to entities in accordance with its associated Regional Reliability Organization's Disturbance data reporting requirements. (R4 R5)

M4. Each Transmission Owner and Generator Owner that is required to install DMEs to meet its Regional Reliability Organization's DME installation requirements, shall have an associated DME maintenance and testing program as defined in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each retain any Disturbance data provided to the Regional Reliability Organization (Requirement 4) for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions is present:

2.1.1 DMEs that meet all the Regional Reliability Organization's installation requirements (in accordance with Requirement 2) were installed at 90% or more but not all of the required locations.

2.1.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with Requirement 4) was provided for 90% or more but not all of the required locations.

2.1.3 Data on required DMEs was incomplete (in accordance with R3)

2.1.4 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 80% or more but less than 90% of the required locations.

2.2.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 80% or more but less than 90% of the required locations.

2.2.3 Recorded Disturbance data was not provided to all required entities (in accordance with R4)

2.2.4 Archived data was not retained for three years (in accordance with Requirement 5).

2.2.5 Documentation of the DME maintenance and testing program provided was complete as required in R6, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions is present:

2.3.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 70% or more but less than 80% of the required locations.

2.3.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 70% or more but less than 80% of the required locations.

2.3.3 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. **Level 4:** There shall be a level four non-compliance if any one of the following conditions is present:

2.4.1 DMEs that meet all Regional Reliability Organization’s installation requirements (in accordance with R2) were installed at less than 70% of the required locations.

2.4.2 Recorded Disturbance data that meets all Regional Reliability Organization’s Disturbance data requirements (in accordance with R4) was provided for less than 70% of the required locations.

2.4.3 DMEs that meet all functional requirements (in accordance with R1) were not installed at all required locations.

2.4.4 Documentation of the DME maintenance and testing program was not provided, or no evidence that the testing program did occur within the identified intervals

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Consideration of Issues and Directives

Project 2007-11 Disturbance Monitoring
PRC-002-2 Disturbance Monitoring and Reporting Requirements

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"For the reasons stated in the NOPR, the Commission will not approve or remand PRC-002-1." "We agree with [American Public Power Association], Alcoa and Otter Tail that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards. Consistent with that goal, the Commission directs the ERO to consider APPA, Alcoa and Otter Tail's suggestions in the Reliability Standards development process as it modifies PRC-002-1 to provide missing information needed for the Commission to act on this Reliability Standard." (see below for American Public Power Association, Alcoa, and Otter Tail discussion)	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1455-56	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances. The use of recording and specifying recording data parameters, greater consistency is achieved in PRC-002-2.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in addressing the completion of this Reliability Standard."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1452	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances.
"Alcoa suggests that the ERO—instead of a Regional Entity—should define the requirements for DME and the type of report it generates. The requirements and equipment specifications should be consistent throughout North America. In addition, Alcoa suggests that the criteria for installation of such equipment should include the necessary monitoring and recording that contribute to analysis and enhance reliability."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1453	Determines the key locations for which Disturbance data must be recorded which eliminates the need for equipment requirements. PRC-002-2 specifies the storage requirements and recording format for the collected data to ensure continent-wide uniformity to expedite event analysis.
"Otter Tail suggests that PRC-002-1 should be developed on an Interconnection wide basis to ensure consistency and promote reliability of the Bulk-Power System."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards	PRC-002-2 will apply on a continent-wide basis.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
	for the Bulk-Power System (Issued March 16, 2007); Paragraph 1454	
"The Commission requires supplemental information for any Reliability Standard that currently requires a regional reliability organization to fill in missing criteria or procedures. Where important information has not yet been provided to us to enable us to complete our review, we are not in a position to approve or remand those Reliability Standards. Accordingly, we will not approve or remand such Reliability Standards until the ERO submits further information. Until such information is provided, compliance with fill-in-the-blank standards should continue on a voluntary basis, and the Commission considers compliance with such Reliability Standards to be a matter of good utility practice."	Fill-in-the-blank Consideration FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 297.	By addressing recording instead of equipment, the Drafting Team has produced a continent-wide standard to have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.

Project 2007-11 – Disturbance Monitoring

PRC-002-2 – Disturbance Monitoring and Reporting Requirements

Mapping Document for PRC-018-1 to PRC-002-2 and PRC-002-1 to PRC-002-2

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that arise from the inherent differences between regional power systems. PRC-018-1 and PRC-002-1 deal with equipment, PRC-002-2 deals with recording. By specifying recording instead of equipment, PRC-002-2 governs the practical capturing of abnormal event data on the BES.

PRC-018-1 Requirements reference PRC-002-1 which requires PRC-018-1 Requirements to be either retired or covered in PRC-002-2.

As used herein, the acronym SOER is Sequence of Events Recording, the acronym FR is Fault Recording, and the acronym DDR is Dynamic Disturbance Recording.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard **PRC-002 Requirements 1-3**) shall have DMEs installed that meet the following requirements:	**R12.** Each Transmission Owner and Generator Owner shall time synchronize all **Sequence of Events Recording** (SOER), **Fault Recording** (FR), and **Dynamic Disturbance Recording** (DDR) data for the bus locations as per Requirement R2 and Elements as per Requirement R7to **within ± 2 milliseconds** of Coordinated Universal Time (UTC), time stamped with or without a local offset. **R13.** Each Transmission Owner and Generator Owner shall provide **Sequence of Event**

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1.1. Internal Clocks in DME devices shall be synchronized to **within 2 milliseconds** or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be **retrievable for ten calendar days**.	**Recording**, **Fault Recording**, and **Dynamic Disturbance Recording** data for the bus locations as per Requirement R2 and Elements as per Requirement R7 to the Reliability Coordinator, Regional Entity, or NERC upon request: 13.1. The recorded data will be provided within 30 calendar days of a request. 13.2. The recorded data will be **retrievable for the period of 10 calendar days** preceding a request. 13.3. Sequence of Events Recording data will be provided in Comma Separated Value (.CSV) format following Attachment 2. 13.4. Fault Recording and Dynamic Disturbance Recording data will be provided in electronic C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files. 13.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).
Notes: PRC-018-1, Requirement R1 is covered in PRC-002-2, Requirements R12 and R13. PRC-018-1 addresses the equipment used for Disturbance monitoring data recording, PRC-002-2 addresses the recorded data. Technological advances made in the types of equipment used to record power system data have made it more effective to direct PRC-002-2 at the recording, not the equipment. Time synchronization and having the data retrievable for 10 days are general parameters that facilitate data analysis. PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirement R13.	
R2. The Transmission Owner and Generator Owner shall each **install DMEs in accordance with** its Regional Reliability Organization's installation	**R1.** Each Transmission Owner shall identify BES bus locations for **Sequence of Events Recording** (SOER) and Fault Recording (FR). 1.1. Bus locations shall be identified using *PRC-002-2 Attachment 1 – Sequence of*

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
requirements (reliability standard **PRC-002 Requirements 1 through 3**). **PRC-002-1** R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event recording**: R1.1. Location, monitoring and recording requirements, including the following: R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1.Location, monitoring and recording requirements, including the following: R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars.	*Events Recording (SOER) and Fault Recording (FR) Locations Selection Methodology.* 1.2. Bus locations shall be assessed at least every five calendar years. **R2**. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the owners of those Elements, within 90 calendar days of determination, that the Elements require **Sequence of Events Recording** (SOER) and Fault Recording (FR). **R3**. Each Transmission Owner and Generator Owner shall have **Sequence of Events Recording** (SOER) for circuit breaker position (open/close) for each of the circuit breakers they own connected to the bus locations as per Requirement R2. **R4.** Each Transmission Owner and Generator Owner shall have **Fault Recording** (FR) at the bus locations as per Requirement R2 to determine the following electrical quantities: 4.1. Phase-to-neutral voltages for each phase of either each line or bus they own. 4.2. Each phase current and the residual or neutral current for the following BES Elements they own: 4.2.1. Transformers that have a low-side operating voltage of 100kV or above. 4.2.2. Transmission Lines.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R2.2.Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements. R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**: R3.1. Location, monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after January 1, 2009.	**R5.** Each Transmission Owner and Generator Owner shall have **Fault Recording** as specified in Requirement R4 that meets the following: 5.1. A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault. 5.2. A minimum recording rate of 16 samples per cycle. 5.3. Trigger settings for at least the following: 5.3.1. Neutral (residual) overcurrent. 5.3.2. Phase undervoltage. **R6.** Each Responsible Entity shall identify BES Elements for which **Dynamic Disturbance Recording** (DDR) is required. 6.1. The Elements shall include the following: 6.1.1. A minimum of one DDR location per 3,000 MW of the Responsible Entity's historical peak system Load, inclusive of Requirement R6, Part 1, Sub-parts 6.1.1 – 6.1.7. 6.1.2 At least one DDR location in each Responsible Entity's footprint. 6.1.3. Generating resource(s) with:

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	6.1.3.1. Gross individual nameplate rating greater than or equal to 500 MVA. 6.1.3.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA. 6.1.4. Locations necessary to monitor all Elements of: • Eastern Interconnection - all permanent Flowgates. • ERCOT Interconnection - major transmission interfaces. • Hydro-Quebec Interconnection - major transmission interfaces. • Western Interconnection - all major transfer paths as defined by the Regional Entity. 6.1.5. Both ends of HVDC terminals (back-to-back or each terminal of a DC circuit) on the AC portion of the converter. 6.1.6. Locations necessary to monitor all Elements of Interconnection Reliability Operating Limits. 6.1.7. Any one Element within a major voltage sensitive area as defined by an in-service undervoltage load shedding (UVLS) program. 6.2. The Elements shall be assessed at least every five calendar years.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	R7. Each Responsible Entity shall notify, within 90 calendar days of determination, each Transmission Owner and Generator Owner of the locations and Elements they own for which **Dynamic Disturbance Recording** is required as established in Requirement R6. **R8.** Each Transmission Owner shall have **Dynamic Disturbance Recording**, for each Element they own as per Requirement R7, to determine the following electrical quantities: 8.1. One phase-to-neutral or positive sequence voltage. 8.2. The phase current on the same phase at the same voltage corresponding to the voltage in Requirement R8, Part 8.1, or the positive sequence current. 8.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 8.4. Frequency of any one of the voltage(s) in Requirement R8, Part 8.1. **R9.** Each Generator Owner shall have **Dynamic Disturbance Recording**, for each Element they own as per Requirement R7, to determine the following electrical quantities: 9.1. Any one phase-to-neutral, phase-to-phase, or positive sequence voltage at either the Generator Step Up Units (GSUs) high-side or low-side voltage level. 9.2. The phase current on the same phase at the same voltage in Requirement R9, Part 9.1, two phase currents for phase-to-phase voltages, or positive sequence current.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	9.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 9.4. Frequency of at least one of the voltages in Requirement R9, Part 9.1. **R10.** Each Transmission Owner and Generator Owner that is responsible for Dynamic Disturbance Recording as per Requirement R7 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, the following is required: 10.1. Triggered record lengths of at least three minutes. 10.2. At least one of the following triggers: • Off nominal frequency trigger set at: Low High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec

<table>
<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td></td><td>• Undervoltage trigger set at:
o No lower than 85% of normal operating voltage for a duration of 5 seconds

R11. Each Transmission Owner and Generator Owner shall have Dynamic Disturbance Recording, for the Elements as per Requirement R7, which conform to the following technical specifications:
11.1. Input sampling rate of at least 960 samples per second.
11.2. Output recording rate of electrical quantities of at least 30 times per second.</td></tr>
<tr><td colspan="2">Notes: PRC-018-1, Requirement R2 and PRC-002-1 Requirements R1-R3 are covered in PRC-002-2, Requirements R1-R2, and R3-R11. PRC-018-1, Requirement R2 references PRC-002-1 Requirements R1-R3. PRC-002-1, Requirements R1-R3 reference equipment installation requirements for FR, SOER, and DDR. The technical parameters of PRC-002-2 pertain to the characteristics and content of the recordings that are needed to facilitate event analysis.</td></tr>
<tr><td>R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region’s installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):</td><td>None.</td></tr>
</table>

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc. R3.8.Monitored electrical quantities, such as voltage, current, etc.	
Notes: PRC-018-1, Requirement R3 is not covered in PRC-002-2. PRC-018-1 Requirement R3 refers to equipment and therefore is not mapped to PRC-002-2 which deals with recorded data and not equipment.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R4. The Transmission Owner and Generator Owner shall each **provide Disturbance data** (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard **PRC-002 Requirement 4**). **PRC-002-1** R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool. 4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	**R13.** Each Transmission Owner and Generator Owner **shall provide Sequence of Event Recording (SOER), Fault Recording (FR), and Dynamic Disturbance Recording (DDR) data** for the bus locations as per Requirement R2 and Elements as per Requirement R7 to the Reliability Coordinator, Regional Entity, or NERC upon request: 13.1. The recorded data will be provided within 30 calendar days of a request. 13.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request. 13.3. Sequence of Events Recording data will be provided in Comma Separated Value (.CSV) format following Attachment 2. 13.4. Fault Recording and Dynamic Disturbance Recording data will be provided in electronic C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files. 13.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
Notes: PRC-018-1, Requirement R4 references PRC-002-1 Requirement R4 which is covered is PRC-002-2, Requirement R13.	
R5. The Transmission Owner and Generator Owner shall each **archive all data** recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	Covered in the Compliance section **1.2** Evidence Retention The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation: The Transmission Owner shall retain evidence of Requirements R1 and R2, Measures M1 and M2 for five calendar years. The Transmission Owner shall retain evidence of Requirements R3, R4, R5, and R8 Measures M3, M4, M5, and M8 for three calendar years.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	The Planning Coordinator and Reliability Coordinator shall retain evidence of Requirements R6 and R7, Measures M6 and M7 for five calendar years. The Generator Owner shall retain evidence of Requirement R9, Measure M9 for three calendar years. The Transmission Owner and Generator Owner shall retain evidence of Requirements R10, R11, R13, and R14, Measures M10, M11, M13, and M14 for three calendar years. If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.
Notes: PRC-018-1, Requirement R5 is covered in the PRC-002-2 Compliance section under Evidence Retention.	
R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes: R6.1. Maintenance and testing intervals	**R14.** Each Transmission Owner and Generator Owner, within 90 calendar days of the discovery of a failure of the **Sequence of Events Recording** (SOER), **Fault Recording** (FR), or **Dynamic Disturbance Recording** (DDR) at the bus locations as per Requirement R2 and Elements as per Requirement R7, shall: • Restore the recording ability. • Report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
and their basis. R6.2. Summary of maintenance and testing procedures.	
Notes: PRC-018-1, Requirement R6 is covered in PRC-002-2, Requirement R14. PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R14 deals with the long term availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability.	

Standard PRC-002-1	Proposed Standard PRC-002-2
R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event recording**: R1.1. Location, monitoring and recording requirements, including the following: R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored	**R1.** Each Transmission Owner shall identify BES bus locations for **Sequence of Events Recording** (SOER) and Fault Recording (FR). 1.1. Bus locations shall be identified using *PRC-002-2 Attachment 1 – Sequence of Events Recording (SOER) and Fault Recording (FR) Locations Selection Methodology.* 1.2. Bus locations shall be assessed at least every five calendar years.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the owners of those Elements, within 90 calendar days of determination, that the Elements require **Sequence of Events Recording** (SOER) and Fault Recording (FR). **R3**. Each Transmission Owner and Generator Owner shall have **Sequence of Events Recording** for circuit breaker position (open/close) for each of the circuit breakers they own connected to the bus locations as per Requirement R2.
Notes: PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirements R1-R3. (See PRC-018-1, Requirement R3 above for additional information.)	
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1. Location , monitoring and recording requirements, including the following: R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored	**R1.** Each Transmission Owner shall identify BES bus locations for Sequence of Events Recording (SOER) and **Fault Recording** (FR). 1.1. Bus locations shall be identified using *PRC-002-2 Attachment 1 – Sequence of Events Recording (SOER) and Fault Recording (FR) Locations Selection Methodology*. 1.2. Bus locations shall be assessed at least every five calendar years. **R2.** Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the owners of those Elements, within 90 calendar days of determination, that the Elements require Sequence of Events Recording (SOER) and **Fault Recording** (FR).

Standard PRC-002-1	Proposed Standard PRC-002-2
element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars. R2.2. Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements.	**R4.** Each Transmission Owner and Generator Owner shall have **Fault Recording** (FR) to determine the following electrical quantities at the bus locations as per Requirement R2: 4.1. Phase-to-neutral voltages for each phase of either each line or bus. 4.2. Each phase current and the residual or neutral current for the following BES Elements: 4.2.1. Transformers that have a low-side operating voltage of 100kV or above. 4.2.2. Transmission Lines. **R5.** Each Transmission Owner and Generator Owner shall have **Fault Recording** as specified in Requirement R4 that meets the following: 5.1. A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault. 5.2. A minimum recording rate of 16 samples per cycle. 5.3. Trigger settings for at least the following: 5.3.1. Neutral (residual) overcurrent. 5.3.2. Phase undervoltage.
Notes: PRC-002-1, Requirement R2 is covered in PRC-002-2, Requirements R1, R2, R4, and R5.	

Standard PRC-002-1	Proposed Standard PRC-002-2
R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**: R3.1. Location , monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and	**R6.** Each Responsible Entity shall identify BES Elements for which **Dynamic Disturbance Recording** (DDR) is required. 6.1. The Elements shall include the following: 6.1.1. A minimum of one DDR location per 3,000 MW of the Responsible Entity's historical peak system Load, inclusive of Requirement R6, Part 1, Sub-parts 6.1.1 – 6.1.7. 6.1.2 At least one DDR location in each Responsible Entity's footprint. 6.1.3. Generating resource(s) with: 6.1.3.1. Gross individual nameplate rating greater than or equal to 500 MVA. 6.1.3.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA. 6.1.4. Locations necessary to monitor all Elements of: • Eastern Interconnection - all permanent Flowgates. • ERCOT Interconnection - major transmission interfaces. • Hydro-Quebec Interconnection - major transmission interfaces. • Western Interconnection - all major transfer paths as defined by the Regional Entity. 6.1.5. Both ends of HVDC terminals (back-to-back or each terminal of a DC circuit)

Standard PRC-002-1	Proposed Standard PRC-002-2
number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	on the AC portion of the converter. 6.1.6. Locations necessary to monitor all Elements of Interconnection Reliability Operating Limits. 6.1.7. Any one Element within a major voltage sensitive area as defined by an in-service undervoltage load shedding UVLS program. 6.2. The Elements shall be assessed at least every five calendar years. **R7.** Each Responsible Entity shall notify, within 90 calendar days of determination, each Transmission Owner and Generator Owner of the locations and Elements they own for which **Dynamic Disturbance Recording** (DDR) is required as per Requirement R7. **R8**. Each Transmission Owner shall have Dynamic Disturbance Recording, for each Element they own as per Requirement R7, to determine the following electrical quantities: 8.1. One phase-to-neutral or positive sequence voltage. 8.2. The phase current on the same phase at the same voltage corresponding to the voltage in Requirement R8, Part 8.1, or the positive sequence current. 8.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 8.4. Frequency of any one of the voltage(s) in Requirement R8, Part 8.1.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R10. Each Transmission Owner and Generator Owner that is responsible for **Dynamic Disturbance Recording** as per Requirement R7 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, the following is required: 10.1. Triggered record lengths of at least three minutes. 10.2. At least one of the following triggers: • Off nominal frequency trigger set at: Low High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set at: o No lower than 85% of normal operating voltage for a duration of 5 seconds

Standard PRC-002-1	Proposed Standard PRC-002-2
	R11. Each Transmission Owner and Generator Owner shall have **Dynamic Disturbance Recording**, for the Elements as per Requirement R7, which conform to the following technical specifications: 11.1. Input sampling rate of at least 960 samples per second. 11.2. Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-002-1, Requirement R3 is covered in PRC-002-2, Requirements R6-R8 and R10-R11.	
R4. The Regional Reliability Organization shall establish requirements for facility owners to **report Disturbance data recorded** by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request.	**R13.** Each Transmission Owner and Generator Owner **shall provide Sequence of Event Recording, Fault Recording, and Dynamic Disturbance Recording data** for the bus locations as per Requirement R2 and Elements as per Requirement R7 to the Reliability Coordinator, Regional Entity, or NERC upon request: 13.1. The recorded data will be provided within 30 calendar days of a request. 13.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request. 13.3. Sequence of Events Recording data will be provided in Comma Separated Value (.CSV) format following Attachment 2. 13.4. Fault Recording and Dynamic Disturbance Recording data will be provided in electronic C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files. 13.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

Standard PRC-002-1	Proposed Standard PRC-002-2
4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool, 4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	
Notes: PRC-002-1, Requirement R4 is covered in PRC-002-2, Requirement R13.	
R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.	**R2.** Each Transmission Owner that identifies BES Elements at the locations established Requirement R1 shall **notify the owners** of those Elements, within 90 calendar days of determination, that the Elements require Sequence of Events Recording and Fault Recording. **R6.** Each Responsible Entity shall identify BES Elements for which **Dynamic Disturbance Recording** (DDR) is required. 6.1. The Elements shall include the following: 6.1.1. A minimum of one DDR location per 3,000 MW of the Responsible

Standard PRC-002-1	Proposed Standard PRC-002-2
	Entity's historical peak system Load, inclusive of Requirement R6, Part 1, Sub-parts 6.1.1 – 6.1.7. 6.1.2 At least one DDR location in each Responsible Entity's footprint. 6.1.3. Generating resource(s) with: 6.1.3.1. Gross individual nameplate rating greater than or equal to 500 MVA. 6.1.3.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA. 6.1.4. Locations necessary to monitor all Elements of: • Eastern Interconnection - all permanent Flowgates. • ERCOT Interconnection - major transmission interfaces. • Hydro-Quebec Interconnection - major transmission interfaces. • Western Interconnection - all major transfer paths as defined by the Regional Entity. 6.1.5. Both ends of HVDC terminals (back-to-back or each terminal of a DC circuit) on the AC portion of the converter. 6.1.6. Locations necessary to monitor all Elements of Interconnection Reliability Operating Limits. 6.1.7. Any one Element within a major voltage sensitive area as defined by an in-service undervoltage load shedding (UVLS) program.

Standard PRC-002-1	Proposed Standard PRC-002-2
	6.2. The Elements shall be assessed at least every five calendar years. **R7.** Each Responsible Entity **shall notify**, within 90 calendar days of determination, each Transmission Owner and Generator Owner of the locations and Elements they own for which **Dynamic Disturbance Recording** (DDR) is required as established in Requirement R6.
Notes: PRC-002-1, Requirement R5 is covered in PRC-002-2, Requirements R2, R6-R7.	
R6. The Regional Reliability Organization shall periodically (**at least every five years**) review, update and approve its Regional requirements for Disturbance monitoring and reporting.	**R1.** Each Transmission Owner shall identify BES bus locations for Sequence of Events Recording (SOER) and Fault Recording (FR). 1.1. Bus locations shall be identified using *PRC-002-2 Attachment 1 – Sequence of Events Recording (SOER) and Fault Recording (FR) Locations Selection Methodology.* 1.2. Bus locations shall be **assessed at least every five calendar** years. **R6.** Each Responsible Entity shall identify BES Elements for which Dynamic Disturbance Recording (DDR) is required. 6.1. The Elements shall include the following: 6.1.1. A minimum of one DDR location per 3,000 MW of the Responsible Entity's historical peak system Load, inclusive of Requirement R6, Part 1, Sub-parts 6.1.1 – 6.1.7. 6.1.2 At least one DDR location in each Responsible Entity’s footprint.

Standard PRC-002-1	Proposed Standard PRC-002-2
	6.1.3. Generating resource(s) with: 6.1.3.1. Gross individual nameplate rating greater than or equal to 500 MVA. 6.1.3.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA. 6.1.4. Locations necessary to monitor all Elements of: • Eastern Interconnection - all permanent Flowgates. • ERCOT Interconnection - major transmission interfaces. • Hydro-Quebec Interconnection - major transmission interfaces. • Western Interconnection - all major transfer paths as defined by the Regional Entity. 6.1.5. Both ends of HVDC terminals (back-to-back or each terminal of a DC circuit) on the AC portion of the converter. 6.1.6. Locations necessary to monitor all Elements of Interconnection Reliability Operating Limits. 6.1.7. Any one Element within a major voltage sensitive area as defined by an in-service undervoltage load shedding (UVLS) program. 6.2. The Elements shall be **assessed at least every five** calendar years.

Standard PRC-002-1	Proposed Standard PRC-002-2
Notes: PRC-002-1, Requirement R6 is covered in PRC-002-2, Requirements R1 and R6.	

Project 2007-11 Disturbance Monitoring

VRF and VSL Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-002-2 – Disturbance Monitoring and Reporting Requirements.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines.

The Disturbance Monitoring and Reporting Requirements Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria –VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed VRF	**Lower**
NERC VRF Discussion	R1 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 establishes the list of Sequence of Events Recordings and Fault Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for establishing a list of BES bus locations for Sequence of Events Recording and Fault Recording using the selection procedure in Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish the list of BES bus locations for Sequence of Events Recording and Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to establish a list of BES bus locations for Sequence of Events Recording and Fault Recording and to review the list every 5 calendar years. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Lower VSL	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 80% but less than 100% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by 30 calendar days or less.
Proposed Moderate VSL	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 70% but less than or equal to 80% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 30 calendar days and less than or equal to 60 calendar days.
Proposed High VSL	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 60% but less than or equal to 70% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 60 calendar days and less than or equal to 90 calendar days.
Proposed Severe VSL	The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for less than or equal to 60% of the required bus locations. OR The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 90 calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-

VRF and VSL Justifications – PRC-002-2, R1	
the Current Level of Compliance	002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the	Non CIP

VRF and VSL Justifications – PRC-002-2, R1	
'weakest link' characteristic, should apply binary VSLs	
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 requires the Transmission Owner to notify the other affected owners to provide Sequence of Events Recordings and Fault Recordings at bus locations selected in Requirement R1. This is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for notifying the other affected owners to provide Sequence of Events Recordings and Fault Recordings at bus locations selected in Requirement R1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to notify the owners of BES bus locations for Sequence of Events Recording and Fault Recording selected in R1 could not directly affect the electrical state or capability of the BES, or the ability to

VRF and VSL Justifications – PRC-002-2, R2	
	effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to notify the owners of BES bus locations for Sequence of Events Recording and Fault Recording selected in R1.
Proposed Lower VSL	The Transmission Owner as directed by Requirement R2 was late in notifying the owners by 10 calendar days or less.
Proposed Moderate VSL	The Transmission Owner as directed by Requirement R2 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.
Proposed High VSL	The Transmission Owner as directed by Requirement R2 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.
Proposed Severe VSL	The Transmission Owner as directed by Requirement R2 was late in notifying one or more owners by greater than 30 calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R2	
Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R3	
Proposed VRF	**Lower**
NERC VRF Discussion	R3 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 provides criteria for Sequence of Events Recording which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Sequence of Events Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Sequence of Events Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to establish criteria for Sequence of Events Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 75% but less than 100% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Moderate VSL	Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 50% but less than or equal to 75% of the

VRF and VSL Justifications – PRC-002-2, R3	
	total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed High VSL	Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 10% but less than or equal to 50% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Severe VSL	Each Transmission or Generator Owner as directed by Requirement R3 implemented from 0% but less than or equal to 10% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: The VSL assignment is for R3 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R3	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R4	
Proposed VRF	**Lower**
NERC VRF Discussion	R4 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely

VRF and VSL Justifications – PRC-002-2, R4	
	affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 75% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Moderate VSL	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 50% but less than or equal to 75% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.

VRF and VSL Justifications – PRC-002-2, R4	
Proposed High VSL	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 10% but less than or equal to 50% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Severe VSL	The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 0% but less than or equal to 10% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	The proposed VSL uses similar terminology to that used in the

VRF and VSL Justifications – PRC-002-2, R4	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative

VRF and VSL Justifications – PRC-002-2, R5	
	conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recordings selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R5.
Proposed Moderate VSL	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R5.
Proposed High VSL	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R5.

VRF and VSL Justifications – PRC-002-2, R5	
Proposed Severe VSL	The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 0% but less than or equal to 10% of the total recording properties as specified in Requirement R5.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VRF and VSL Justifications – PRC-002-2, R5	
on A Single Violation, Not on A Cumulative Number of Violations	
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 establishes the list of Dynamic Disturbance Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.

VRF and VSL Justifications – PRC-002-2, R6	
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for identifying BES Elements for Dynamic Disturbance Recording. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to identify BES Elements for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which identifies BES Elements within specified criteria and to review the list every 5 calendar years. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 80% but less than 100% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by 30 calendar days or less.
Proposed Moderate VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 70% but less than or equal to 80% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 30 calendar days and less than or equal to 60 calendar days.
Proposed High VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 60% but less than

VRF and VSL Justifications – PRC-002-2, R6	
	or equal to 70% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 60 calendar days and less than or equal to 90 calendar days.
Proposed Severe VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for less than or equal to 60% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 90 calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous	Guideline 2a: The VSL assignment is for R6 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R6	
Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R7	
Proposed VRF	**Lower**
NERC VRF Discussion	R7 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 requires the Responsible Entity to notify the owners to provide Dynamic Disturbance Recordings for Elements selected in R6. This is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for the Responsible Entity to notify the owners of the Elements for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to notify the owners of the Elements selected for Dynamic Disturbance Recording in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to notify the owners of BES Elements selected for Dynamic Disturbance Recording selected in R6.
Proposed Lower VSL	The Responsible Entity as directed by Requirement R7 was late in notifying the owners by 10 calendar days or less.
Proposed Moderate VSL	The Responsible Entity as directed by Requirement R7 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.

VRF and VSL Justifications – PRC-002-2, R7	
Proposed High VSL	The Responsible Entity as directed by Requirement R7 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.
Proposed Severe VSL	The Responsible Entity as directed by Requirement R7 was late in notifying one or more owners by greater than 30 calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-002-2, R7	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R8	
Proposed VRF	**Lower**
NERC VRF Discussion	R8 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to

VRF and VSL Justifications – PRC-002-2, R8	
	effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 and 8.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all

VRF and VSL Justifications – PRC-002-2, R8	
	applicable BES Elements.
Proposed Severe VSL	The Transmission Owner failed to implement DDR as directed by Parts 8.1 through 8.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VRF and VSL Justifications – PRC-002-2, R8	
on A Single Violation, Not on A Cumulative Number of Violations	
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R9	
Proposed VRF	**Lower**
NERC VRF Discussion	R9 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.

VRF and VSL Justifications – PRC-002-2, R9	
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Generator Owner failed to implement DDR as directed by Requirement R9, Parts 9.1 through 9.4.
FERC VSL G1	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1

VRF and VSL Justifications – PRC-002-2, R9	
Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	(enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5	Non CIP

VRF and VSL Justifications – PRC-002-2, R9	
Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R10	
Proposed VRF	**Lower**
NERC VRF Discussion	R10 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards**

VRF and VSL Justifications – PRC-002-2, R10	
	This requirement establishes the need for continuous data recording and storage for Dynamic Disturbance Recordings established in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 75% but less than 100% of the Elements they own as per Requirement R7.
Proposed Moderate VSL	The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 50% but less than or equal to 75% of the Elements they own as per Requirement R7.
Proposed High VSL	The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 0% but less than or equal to 50% of the Elements they own as per Requirement R7.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to implement continuous or non-continuous DDR, as directed in Requirement R10, for the Elements they own as per Requirement R7.
FERC VSL G1	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that

VRF and VSL Justifications – PRC-002-2, R10	
Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single	Non CIP

VRF and VSL Justifications – PRC-002-2, R10	
lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R11	
Proposed VRF	**Lower**
NERC VRF Discussion	R11 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement established technical specifications for Dynamic

VRF and VSL Justifications – PRC-002-2, R11	
	Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish technical specifications for Dynamic Disturbance Recording selected in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R11 contains only one objective which is to establish technical specifications for Dynamic Disturbance Recording selected in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R11.
Proposed Moderate VSL	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R11.
Proposed High VSL	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R11.
Proposed Severe VSL	The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 1% but less than or equal to 10% of the total recording properties as specified in Requirement R11.
FERC VSL G1 Violation Severity Level Assignments Should Not	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture

VRF and VSL Justifications – PRC-002-2, R11	
Have the Unintended Consequence of Lowering the Current Level of Compliance	data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer	Non CIP

VRF and VSL Justifications – PRC-002-2, R11	
network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R12	
Proposed VRF	**Lower**
NERC VRF Discussion	R12 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 requires time synchronization of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations established in R1 and R6. The team could not identify

VRF and VSL Justifications – PRC-002-2, R12	
	other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failures to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective which is to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 90% but less than 100% of the bus locations established in Requirements R1 and Elements established in Requirement R6 as directed by Requirement R12.
Proposed Moderate VSL	The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 80% but less than or equal to 90% of the bus locations established in Requirements R1 and Elements established in Requirement R6 as directed by Requirement R12.
Proposed High VSL	The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 70% but less than or equal to 80% of the bus locations established in Requirements R1 and Elements established in Requirement R6 as directed by Requirement R12.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to implement time synchronization for Sequence of Events Recording, Fault

VRF and VSL Justifications – PRC-002-2, R12	
	Recording, and Dynamic Disturbance Recording for less than 70% of the bus locations established in Requirements R1 and Elements established in Requirement R6 as directed by Requirement R12.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VRF and VSL Justifications – PRC-002-2, R12	
Violations	
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R13	
Proposed VRF	**Lower**
NERC VRF Discussion	R13 is administrative in nature and a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R13 provides criteria around timelines for providing the data and the data format. This is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF

VRF and VSL Justifications – PRC-002-2, R13	
	was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria on providing Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R6.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R13 contains only one objective which is to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data within the specified criteria. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 30 calendar days but less than 40 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 90% but less than 100% in the proper data format.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 40 calendar days but less than or equal to 50 calendar days from the request.

VRF and VSL Justifications – PRC-002-2, R13	
	OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 80% but less than or equal to 90% in the proper data format.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 50 calendar days but less than or equal to 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 70% but less than or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 70% but less than or equal to 80% in the proper data format.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 failed to provide the requested data more than 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided less than or equal to 70% in the proper data format.

VRF and VSL Justifications – PRC-002-2, R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R13 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single	Non CIP

VRF and VSL Justifications – PRC-002-2, R13	
lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R14	
Proposed VRF	**Lower**
NERC VRF Discussion	R14 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R14 provides criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.

VRF and VSL Justifications – PRC-002-2, R14	
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to follow the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R14 contains only one objective which is to establish criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days but less than 100 calendar days after discovery of the failure.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days but less than or equal to 110 calendar days after discovery of the failure.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days but less than or equal to 120 calendar days after discovery of the failure.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R14 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure.
FERC VSL G1 Violation Severity Level Assignments Should Not	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture

VRF and VSL Justifications – PRC-002-2, R14	
Have the Unintended Consequence of Lowering the Current Level of Compliance	data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R14 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer	Non CIP

VRF and VSL Justifications – PRC-002-2, R14	
network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2007-11 Disturbance Monitoring
PRC-002-2

Ballot and Non-Binding Poll Now Open through December 16, 2013

Now Available

A ballot for **PRC-002-2 - Disturbance Monitoring and Reporting Requirements** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels is open through **8 p.m. Eastern on Monday, December 16, 2013**.

Instructions for Balloting
Members of the ballot pools associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

Standards Development Process
The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
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Atlanta, GA 30326
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Standards Announcement

Project 2007-11 Disturbance Monitoring

Ballot Pools Forming: November 1 – December 2, 2013
Formal Comment Period: November 1 – December 16, 2013

Additional Document Posted for Comment:
Cost Effectiveness Comment Period: November 1 – December 2, 2013

Upcoming:
Ballot and Non-Binding Poll: December 6-16, 2013

Now Available

A formal comment period for **PRC-002-2 - Disturbance Monitoring and Reporting Requirements** is open through **8 p.m. Eastern on Monday, December 16, 2013** and ballot pools are forming through **8 a.m. Monday, December 2, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

NERC has developed a Cost Effective Analysis Process (CEAP) to introduce the concept of cost consideration and effectiveness into the development of new and revised standards. As part of the pilot of the CEAP, NERC is proposing to conduct a CEA to provide information about cost impacts of draft Reliability Standards and their relative effectiveness, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of the standard.

A pilot of "Phase II" of the CEAP, the CEA, is posted for industry comment for the Disturbance Monitoring Project through **8 p.m. Eastern on Monday, December 2, 2013**. More information about the CEAP is available here.

Transmission Owners – Please note the following:
An Excel Workbook has been designed to assist Transmission Owners in using the methodology (referred to as the Median Method) discussed in Attachment 1. This workbook has been posted along with the other PRC-002-2 materials during this comment period to give Transmission Owners the opportunity to try out Requirement R1's bus location method by either using their entire system data, or a selected portion of their systems to obtain a full or partial listing of the bus locations that would have to be included in for SOER and FR.

Instructions for Joining Ballot Pool(s)

Ballots pools are being formed for the standard and non-binding poll for PRC-002-2. Registered Ballot Body members must join both ballot pools to be eligible to vote in the balloting of PRC-002-2 and to submit an opinion for the non-binding poll of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool.

During the pre-ballot window, members of the ballot pool may communicate with one another by using the "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool email list servers for the ballot pools are:

Ballot: bp-2007-11_DM_Ballot_in
Non-Binding Poll: bp-2007-11_DM_NBP_in

Instructions for Commenting

A formal comment period is open for PRC-002-2 through **8 p.m. Eastern on Monday, December 16, 2013**. A CEA has also been posted for industry comment and is open through **8 p.m. Eastern on Monday, December 2, 2013**. Please use the links below to the electronic comment forms to submit comments:

PRC-002-2
Cost Effective Analysis

If you experience any difficulties in using the electronic forms, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

A ballot and non-binding poll of the associated VRFs and VSLs will be conducted **December 6, 2013** through **8 p.m. Eastern Monday, December 16, 2013**.

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Project 2007-11 Disturbance Monitoring

Ballot Pools Forming: November 1 – December 2, 2013
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Additional Document Posted for Comment:
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Now Available

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During the pre-ballot window, members of the ballot pool may communicate with one another by using the "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool email list servers for the ballot pools are:

Ballot: bp-2007-11_DM_Ballot_in
Non-Binding Poll: bp-2007-11_DM_NBP_in

Instructions for Commenting

A formal comment period is open for PRC-002-2 through **8 p.m. Eastern on Monday, December 16, 2013**. A CEA has also been posted for industry comment and is open through **8 p.m. Eastern on Monday, December 2, 2013**. Please use the links below to the electronic comment forms to submit comments:

PRC-002-2
Cost Effective Analysis

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-Ballot Pools
-Current Ballots
-Ballot Results
-Registered Ballot Body
-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2007-11 DM Ballot_in
Ballot Period:	12/6/2013 - 12/16/2013
Ballot Type:	Initial
Total # Votes:	315
Total Ballot Pool:	383
Quorum:	**82.25 % The Quorum has been reached**
Weighted Segment Vote:	43.29 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	102	1	25	0.316	54	0.684	0	5	18
2 - Segment 2	8	0.6	0	0	6	0.6	0	1	1
3 - Segment 3	86	1	19	0.306	43	0.694	0	5	19
4 - Segment 4	29	1	10	0.435	13	0.565	0	1	5
5 - Segment 5	87	1	21	0.328	43	0.672	0	5	18
6 - Segment 6	51	1	13	0.289	32	0.711	0	1	5
7 - Segment 7	4	0.2	2	0.2	0	0	0	1	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	1	0
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.7	6	0.6	1	0.1	0	1	0
Totals	**383**	**7.1**	**102**	**3.074**	**192**	**4.026**	**0**	**21**	**68**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Hudson Gas & Electric Corp.	Frank Pace	Affirmative	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tommy Drea - DPC)
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion supports previously submitted Dominion comments)
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
				COMMENT

1	El Paso Electric Company	Pablo Onate	Negative	RECEIVED
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg	Negative	COMMENT RECEIVED
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Keys Energy Services	Stanley T Rzad	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Negative	COMMENT RECEIVED
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnesota Power, Inc.	Randi K. Nyholm	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO's NSRF's Comments)
1	Montana Dakota Utilities Co.	Teresa Hendrickson	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC Comments.)
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD & SPP)
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (cite to NPCC and NYPA)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO's Standard Review Forum comments)
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co of NY, Inc.)
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE to submit comments.)
1	Potomac Electric Power Co.	David Thorne	Negative	COMMENT RECEIVED
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted under title PPL NERC Registered Entities)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Public Service Enterprise Group)
1	Public Utility District No. 1 of Okanogan	Dale Dunckel	Abstain	

	County			
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman - Puget Sound Energy)
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Sam Rayburn G&T Inc.	William M Bateman		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik		
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (We agree with the SERC PCS comments.)
1	South Texas Electric Cooperative	Renee Davidson		
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (npcc)
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Negative	COMMENT RECEIVED

2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Services	Amy J Miller	Negative	COMMENT RECEIVED
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI comments)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc & Affiliates)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Negative	COMMENT RECEIVED
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power

				Agency)
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc & Affiliates)
3	Detroit Edison Company	Kent Kujala	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	El Paso Electric Company	Rhonda Bryant	Negative	SUPPORTS THIRD PARTY COMMENTS - (see comments provided by Pablo Onate of El Paso Electric Company)
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough		
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover		
3	Guadalupe Valley Electric Cooperative	Robert B Christmas		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	COMMENT RECEIVED
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lee County Electric Cooperative	David A Hadzima	Affirmative	
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT

				RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF Comments.)
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC comments)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by both NYPA and NPCC)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co of NY, Inc.)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Negative	COMMENT RECEIVED
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pepco Holdings Inc & Affiliates)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (We agree with the SERC PCS comments.)

3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments will be submitted by Chang Choi.)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dale Fredrickson)
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Detroit Edison Company	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency and PJM)
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	

4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF comments)
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments of Seminole Electric Cooperative (Bret Galbraith))
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dale Fredrickson We Energies)
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Ameren comments)
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments provided by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		

5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Abstain	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	COMMENT RECEIVED
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Dairyland Power Coop.	Tommy Drea	Negative	COMMENT RECEIVED
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Energy	Mark Stefaniak	Negative	SUPPORTS THIRD PARTY COMMENTS - Kathleen Black DTE - (David Szulczewski, DTE Electric)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	COMMENT RECEIVED
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pablo Onate)
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
				SUPPORTS THIRD PARTY

5	Lakeland Electric	James M Howard	Negative	COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Negative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	NaturEner USA, LLC	Andrew S Ace		
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYPA comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Ontario Power Generation Inc.	David Ramkalawan	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	COMMENT RECEIVED
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (We agree with the SERC PCS comments.)

5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith for Seminole Electric Cooperative Inc)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dale Fredrickson)
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	COMMENT RECEIVED
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)

6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	El Paso Electric Company	Luis Rodriguez	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pablo Onate)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA Comments)
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Lower Colorado River Authority	Michael Shaw		
6	Luminant Energy	Brenda Hampton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation (Rick Terrill))
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	New York Power Authority	Saul Rojas	Negative	COMMENT RECEIVED
6	Northern California Power Agency	Steve C Hill	Negative	COMMENT RECEIVED
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Negative	COMMENT RECEIVED
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (We agree with the SERC

				PCS comments.)
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
7	Alcoa, Inc.	Thomas Gianneschi	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Praxair Inc.	David Meade		
7	Valero Services, Inc.	Lee W Morris	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner	Affirmative	
8		David L Kiguel	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Protection and Control Subcomittee (PCS)- submitted 12/16/13 by David Green)
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

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Non-binding Poll Results

Project 2007-11 PRC-002-2

Non-binding Poll Results	
Non-binding Poll Name:	2007-11 DM Non-Binding Poll
Poll Period:	12/6/2013 - 12/16/2013
Total # Opinions:	273
Summary Results:	79.82% of those who registered to participate provided an opinion or an abstention; 36.11% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tommy Drea - DPC)

1	Dayton Power & Light Co.	Hertzel Shamash		
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Negative	COMMENT RECEIVED
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg	Negative	COMMENT RECEIVED
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Keys Energy Services	Stanley T Rzad	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida

				Municpal Power Agency (FMPA))
1	Lee County Electric Cooperative	John Chin	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Negative	COMMENT RECEIVED
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO's NSRF's Comment Sheet)
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC Comments.)
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (cited NYPA and NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Southwest Power Pool)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO's Standard Review Forum comments)
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co of NY, Inc.)
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE to submit comments.)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted under title PPL NERC Registered Entities)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman - Puget Sound Energy)
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	

1	Salt River Project	Robert Kondziolka	Affirmative	
1	Sam Rayburn G&T Inc.	William M Bateman		
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik		
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (We agree with the SERC PCS comments.)
1	South Texas Electric Cooperative	Renee Davidson		
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System	Barbara Constantinescu	Affirmative	

	Operator			
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Services	Amy J Miller	Negative	COMMENT RECEIVED
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI comments)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Negative	COMMENT RECEIVED
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Florida Municipal Power Agency)
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	El Paso Electric Company	Rhonda Bryant	Negative	SUPPORTS THIRD PARTY COMMENTS - (See comments of Pablo Onate of El Paso Electric Company)
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough		
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover		
3	Guadalupe Valley Electric Cooperative	Robert B Christmas		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	COMMENT RECEIVED
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lee County Electric Cooperative	David A Hadzima	Affirmative	
3	Lincoln Electric System	Jason Fortik	Abstain	

3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MISO NSRF Comments.)
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Abstain	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by both NYPA and NPCC)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co of NY, Inc.)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		

3	Portland General Electric Co.	Thomas G Ward	Negative	COMMENT RECEIVED
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (We agree with the SERC PCS comments.)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments will be submitted by Chang Choi.)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Florida Municipal Power Agency)
4	Detroit Edison Company	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative (Bret Galbraith))
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dale Fredrickson We Energies)
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Amerenue	Sam Dwyer	Abstain	

5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments provided by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	COMMENT RECEIVED
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Dairyland Power Coop.	Tommy Drea	Negative	COMMENT RECEIVED
5	DTE Energy	Mark Stefaniak	Negative	SUPPORTS THIRD PARTY COMMENTS - (David Szulczewski, DTE Electric)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	COMMENT RECEIVED
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Pablo Onate)
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Karin Schweitzer	Negative	COMMENT RECEIVED
5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC and NYPA comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oglethorpe Power Corporation	Bernard Johnson		

NERC

5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Ontario Power Generation Inc.	David Ramkalawan	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	COMMENT RECEIVED
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (We agree with the SERC PCS comments.)
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Galbraith for Seminole Electric Cooperative Inc)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern

				Company)
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
6	AEP Marketing	Edward P. Cox	Abstain	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	COMMENT RECEIVED
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	El Paso Electric Company	Luis Rodriguez	Negative	SUPPORTS THIRD PARTY COMMENTS - (Pablo Onate)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (FMPA Comments)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Lower Colorado River Authority	Michael Shaw		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Negative	COMMENT RECEIVED
6	Northern California Power Agency	Steve C Hill	Negative	COMMENT RECEIVED
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
6	Omaha Public Power District	Douglas Collins		
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis	Negative	COMMENT RECEIVED
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (We agree with the SERC PCS comments.)
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting

				comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chang Choi)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
7	Alcoa, Inc.	Thomas Gianneschi	Abstain	
7	Occidental Chemical	Venona Greaff	Affirmative	
7	Praxair Inc.	David Meade		
8		Debra R Warner	Affirmative	
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Protection and Control Subcomittee - submitted 12/16/13 by David Green)
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	

Individual or group. (73 Responses)
Name (42 Responses)
Organization (42 Responses)
Group Name (31 Responses)
Lead Contact (31 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (6 Responses)
Comments (73 Responses)
Question 1 (57 Responses)
Question 1 Comments (67 Responses)
Question 2 (54 Responses)
Question 2 Comments (67 Responses)
Question 3 (57 Responses)
Question 3 Comments (67 Responses)
Question 4 (56 Responses)
Question 4 Comments (67 Responses)
Question 5 (44 Responses)
Question 5 Comments (67 Responses)
Question 6 (55 Responses)
Question 6 Comments (67 Responses)
Question 7 (0 Responses)
Question 7 Comments (67 Responses)

Individual
Jonathan Meyer
Idaho Power Company
Yes
Yes
Yes
Yes
Yes
No
Protection Engineering: The 4 year implementation plan could be challenging to fit into our project process. We employ a 3 year cycle with definition in year 1, scope/design in year 2, and construction in year 3. Any delays in any given year could cause us to exceed the requirement.
As related to R5.1, we wonder if there is a need for both bulleted items. We are assuming that these two bulleted items represent an "OR" otherwise they would be listed as two separate Req. Further, if "At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault" is sufficient, why is there an option to capture 50 cycles of data? We also request clarification of R8 to either explicitly allow or not allow the power measurements to be calculated from the voltage and current used in 8.1 & 8.2. In the WECC footprint, we believe Sequence of Events is typically abbreviated SER.
Individual
Brenda Frazer
Edison Mission Marketing & Trading Inc.

Yes
Yes
Yes
Yes
Yes
Yes
While we believe that our Wind sites have a low risk of being one of the selected entities required to install & maintain disturbance monitoring equipment, the standard provides no compensation for the purchase, installation, and maintenance of this equipment. It may a significant burden on our projects.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
Yes
Yes
No
R2 and R7 have 10 day time limits before elevating to the next Violation Security Level. This is too short and should be increased to 30 days.
Yes
The proposed standard still needs work before it is acceptable. The following items need to be addressed: 1. The standard requires all owners of identified BES elements to implement the various types of recording. However, for jointly owned facilities, this puts co-owners in a position whereby they can be held in violation of the standard if the operating/maintenance entity of a co-owned facility does not implement and maintain compliance with the standard. For jointly owned facilities, the standard should specifically address which of the co-owners (preferably the co-owner that operates or maintains the facility) is responsible for compliance with the standard. 2. Requirement 14 needs to be re-written. As it is now written, R14 requires that a TO or GO formally report to the Regional Entity an outage of any of the recording capabilities covered by the standard along with a Corrective Action Plan. However, in the “Rationale for R14” discussion that is included it is clear that the intent or this requirement is to require the TO/GO to report the problem only if they cannot restore the lost recording capability within 90 days. The requirement needs to be re-written to state the actual intent because as it is now written, one must contact the Regional entity every time the recording capability goes out, no matter how long it went out for. 3. Requirements R10 through R13 all seem to be required specifications and shouldn’t have their own requirements but could rather be combined into an Appendix to the standard. 4. The standard should allow for monitoring/recording up to the capability of the equipment presently installed (this is not referring to the capability of the presently installed recording capability but rather the presently installed BES equipment capability). A utility shouldn’t have to install major equipment (CCVTs, breakers, etc) just to meet the standard

if their presently installed equipment doesn't allow adequate monitoring. 5. In Requirement R3 it is not clear if a GO will be required to monitor a low side generator breaker. The standard refers to breaker connected to the identified bus location. If this refers to each breaker that is directly connected to the bus location, the requirement should use the term "directly". Without qualifying as such, the question remains as to whether the low side breaker qualified as being connected to the bus since it is connected to the bus through the GSU transformer.
Group
Pepco Holdings Inc & Affiliates
David Thorne
Yes
Yes
Yes
Yes
Yes
No
1) Implementation for Requirement R14, as presently written, applies 9 months after the standard is approved. This requirement needs to be clarified. It should only apply to those SOE, FR, and DDR devices that have been installed in accordance with, and meet the requirements of, this standard. Legacy DME equipment that may exist at one of the busses identified in R1, which does not meet the requirements of this standard, should not be subject to Requirement R14, until the equipment is upgraded, or replaced, to meet the full requirements of this standard. This clarification needs to be made, or, the implementation for R14 should be moved to coincide with the timetable for Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13. 2) The timetable for implementation of Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13 allows an entity that owns only one bus location four years to achieve compliance. However, Entities must be compliant with a reassessed list from Requirement R1, Part 1.2 or R6, Part 6.2 within three years following notification of the list. Why this discrepancy? Four years seems appropriate in both cases, in order to schedule the numerous outages necessary to install the equipment, particularly if generation units are connected to the bus.
1) Requirement R2 should be re-written as follows: Each transmission Owner that identifies BES Elements, which are owned by other entities, at the locations established in Requirement R1 shall notify the owners of those Elements ….. By adding the phrase - which are owned by other entities - eliminates the need to unnecessarily provide documentation that it notified itself of the requirement. 2) Requirement R4 Part 4.1 should be re-written as follows: Phase-to-neutral voltages for each phase of either each BES line or bus. The term BES must be added to provide clarity and to be consistent with Part 4.2 and the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide voltage monitoring on non BES radial lines, or distribution transformers connected to the bus. 3) Requirement R8 should be re-written as follows: Each Transmission Owner shall have Dynamic Disturbance Recording (DDR), for each BES Element they own as per Requirement R7, to determine the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES radial lines, or distribution transformers connected to the bus. 4) Requirement R9 should be re-written as follows: Each Generator Owner shall have Dynamic Disturbance Recording (DDR), for each BES Element they own as per Requirement R7, to determine the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES station service transformers connected to the bus. 5) Requirement R13 Part 13.2 poses an

indeterminate requirement on the size of the hard drive required to archive data. The present requirement states that the data will be retrievable for the period of 10 calendar days preceding a request. However, there is no requirement on how long after an event the request might be made. If the request was not made until six months after the event, would the data have to be retrievable for six months after the event? In order to place certainty on this data storage requirement Part 13.2 should be re-written as follows: The recorded data will be retrievable for a period of 10 calendar days following an event. This places a limit on data storage capacity and also makes it clear that a request for data must be made within 10 calendar days of the event. 6) Requirement R14 needs to be re-written to be consistent with the intent of the requirement as expressed in the shaded box describing the Rationale for R14. As presently written, R14 requires that the Owner must both restore recording ability AND report the inability to record data to the Regional Entity. To be consistent with the Rationale, Requirement R14 should be re-written as follows: Each Transmission Owner and Generation Owner, upon discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recording (DDR) at the bus locations as per Requirement R2 and elements as per Requirement R7, shall restore the recording ability within 90 calendar days, OR , if the recording capability cannot be restored within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability. 7) In the Guidelines and Technical Basis in the next to last paragraph of the section on Guideline for Requirement R1 it states that there is no requirement for SOER and FR for generating units. Later in the section on Guideline for Requirement R4 it states that generator step-up transformers are excluded from fault recording. If so, why is Generator Owner listed as an applicable entity in Requirement R4? It makes sense to list them in R3, since they may own breakers connected to Transmission Owners bus, but the GSU Transformer, station service transformer, and generator itself would not qualify for Fault Recording. 8) There is no specific requirement for the sampling rate for SOER within the standard itself. In the Guidelines and Technical Basis section on Guideline for Requirement R5 it states that a minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for SOER. There are a vast number of microprocessor relays currently installed on the system that have a sampling rate of 16 samples per cycle for analog inputs, however, the digital inputs, which would be used for SOE recording, are only sampled every quarter cycle. Existing regional DME standards and criteria recognize this and permit these types of microprocessor relays to be acceptable for both FR and SOER applications. As such, in order to allow these devices to continue to be an acceptable application, we would suggest two requirements be added for SOER devices, similar to that included in the RFC DME criteria, that states: SOER recording equipment should be capable of determining and recording the time that an input is received to within one quarter of an electrical cycle (or less) of input change of state. SOER recording equipment should have time stamp capability to record seconds to at least three decimal places (i.e. ss.000). 9) The bus selection methodology in Attachment 1 defines a single bus location as including any bus Elements at the same voltage level within the same physical location sharing a common ground grid. However, there are some substations that have multiple busses at the same voltage level within the same physical location that share a common ground grid, but are not physically connected together. They are either physically isolated from one another, or connected via a normally open tie switch or breaker. In these cases, the above definition does fit this scenario and each bus should be evaluated independently. To address this scenario perhaps the definition should be re-written as follows: A single bus location includes any bus Elements at the same voltage level that are connected together within the same physical location sharing a common ground grid.
Individual
Dan Roethemeyer
Dynegy
Yes
Yes
No

1.) Regional Standard PRC-002-NPCC-01 which recently became effective conflicts with PRC-002-2. There is no bright line 500 MVA criteria for GOs to install DDR in the NPCC Regional Standard which instead allows the Reliability Coordinator to make the call. Also, it is not clear from R6 if the GO is supposed to wait for notification from the RC to install DDR or if the GO should go ahead and install DDR at units >500 MVA on their own. 2.) It's recognized that the SDT researched the 500 MVA cutoff point to cover what was felt to be an appropriate percentage of US generating assets. Based on comparisons with other Regional Criteria and Standards, this number seems low – some use a number of 1000 MVA. A compromise cutoff of 750 MVA is suggested. 3.) PRC-002-NPCC-01 requires installation of SOER and FR at generating units while PRC-002-2 specifically states SOER and FR are not required at generating units. Some GOs have spent considerable capital dollars to comply with a new NPCC Regional Standard, only to have a new conflicting continent wide Standard proposed.
No
The two/three/four year requirement for a GO to be 25%/50%/100% compliant should be increased to three/four/five years to give more time to budget these large capital expenditures.
Regional Standard PRC-002-NPCC-01 technical specifications for DDR conflict with PRC-002-2 technical specifications. The NPCC Regional Standard R9 specifies a DDR recording rate of 6 times per second while PRC-002-2 specifies 30 times per second. Conflicts with the Regional Standard should be removed so entities are not penalized for Regional Standard compliance.
Group
Modeling Working Group
Jose Conto
Yes
MWG finds that requirements for data retention are essential to this standard but are missing in the current draft. MWG recommends including a requirement that all triggered data recordings be retained for a minimum of 2 years and that all continuous data recordings be retained for a minimum of 30 days. MWG also recommends including a requirement that all continuous data recordings be scanned against the set of triggers defined in R10 and those portions of the continuous recordings that fall within the time periods defined by those triggers be retained for a minimum of 2 years.
Group
Northeast Power Coordinating Council
Guy Zito
No
The definition for SOER optionally includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit breaker position. The purpose of the standard is to "have adequate data available to facilitate analysis of BES disturbances". We don't see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis. We could support the definitions as used within this standard but do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should

be given to using the word “data” in place of the word “recording”, such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD. Also the definition of SOER presently uses the phrase “… status of Elements, which may include protection and control devices.” We recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status.
Yes
We agree with the idea behind the methodology, however the term BES bus locations is not defined. The NERC BES definition applies to Elements, not buses. Continuing to Requirement R2, a TO might not have visibility to BES classification of elements it does not own. Planning/Reliability Coordinator would be a more applicable functional entity for this role. They should also be responsible for reaching out to the GO’s with notification for SOER and FR. A TO has no authority to perform this function; a GO might also question the bus selection and ask that another TO bus be included instead. The methodology in Attachment 1 is overly complicated (9 steps); and following eight of these required steps, it is then left up to the T.O. to add “discretionary” stations, if desired. Just using the highest 11 station fault MVA values may not be the most accurate. Contributions from a foreign, nearby utility can raise a station’s fault values, even though the station itself is not that critical to the listing entity. Using “Station” instead of “Bus” or “Location” would be more definitive. e.g. a 230 kV “Station”, a 345 kV “Station”,…). The term “bus” can be defined in different ways, so can “location.”
Yes
No
Requirement R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but sub-Parts 6.1.1 and 6.1.2 are not criteria for “Elements”, but rather, they are criteria based on demand size and footprint. It would be helpful if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., sub-Parts 6.1.1 and 6.1.2), and one for the location/element (sub-Parts 6.1.3 to 6.1.6). Suggest moving the minimum quantities in sub-Parts 6.1.1 (minimum 1 DDR per 3000 MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the requirements for sub-Parts 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc…), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable requirements, and state that additional DDR locations are only needed if fulfilling the first 5 do not meet the two extra minimum quantities requirements. Sub-Part 6.1.3--Needs to be clarified to make it understood how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples would be helpful. Sub-Part 6.1.4, first bullet – Requiring monitoring of all “Flowgates” on the Eastern Interconnection seems arbitrary and diminishes the role of those with the best understanding of the nature of their system to determine the appropriate locations for DDRs. If “Flowgate” monitoring is required, this item should include a link to the official list of NERC Flowgates so that the “Responsible Entity” knows where they need to install DDRs. For example, the NY-NE interface is one of the official NERC Flowgates, which means that entities will need a DDR at each of eight stations that interconnect with New York; while entities on the other end of the interconnection in NE will need to do the same. Regarding “monitor all Elements of: all permanent Flowgates”. If a Flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every transformer need to be monitored (low side or high side side)? Please show some typical examples. The guideline for R6 included in the draft fails to explain why all Flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the maximum pre-contingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with sub-Part 6.1.3.2 because there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. Clarify that DDR is for “all permanent Flowgates” ONLY if the Flowgates are BES Elements. Sub-Part 6.1.5 – this will require the installation of DDRs at HVDC facilities that are smaller than the generator requirement listed in sub-Part 6.1.3 (500 MW). This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities. Sub-Part 6.1.6 – This requirement could

lead to installation of DDRs at many substations to just capture one flow that is part of an IROL. Also, DDR data is of little value for IROLs that are thermal in nature. Sub-Part 6.1.6/Guideline - The Guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLs) should be monitored. The NERC lists including all elements associated with IROLs are very extensive. This requirement will dramatically increase the number of the DDRs need to be installed. This could cause too excessive burden on some TOs. Also, there is nothing to limit the burden which can be placed on the TO by a Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable). Depending on the impact, a 3-year implementation plan might not be achievable.
No
The VSLs don't take into account the size of responsible entity. Larger entities should be given more time.
No
Recommend updating the "entity" for the following requirements on the Implementation Plan Summary: R8 - TO R9 - GO R10 - TO/GO The Implementation Plan doesn't take into account the size of responsible entity. Larger entities should be given more time (see response to Question 5).
Regarding Attachment 1: a) The term "BES bus location" is not clear. There could be two or more BES bus locations at the same physical location (substation). The definition of "BES bus" could not be found. b) Step 7 of Attachment 1 does not specify how to round the 10% of the BES bus locations, determined in Step 6, with the highest maximum available calculated three phase short circuit MVA. c) Step 8 of Attachment 1 does not specify how to round the additional 10% of the BES bus locations determined in Step 6. d) Attachment 1 does not specify how to distribute an odd number for 20% of the BES bus locations between b) and c) from above. In Part 1.2 and Part 6.2, what prevents a TO or RE from assessing the locations and elements too frequently? As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability where monitoring is really needed. Frequent assessments could move locations above and below the minimum criteria line and create confusion. We agree with R1, but do not see the need for R2 because through R1 and Attachment 1 each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR). There is not another owner(s) that a TO needs to communicate the list to, unless the "list of BES bus locations that it owns" stated in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that's the case, Step 1 in Attachment 1 needs to be clarified. In R2, it infers that the TO as part of R1 developed a list of Elements, however R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest R2 be reworded to say "Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify…". If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. The intent of Requirement R2 is for Transmission Owners to notify "other" owners of BES Elements, as explained in the Rationale statement. The requirement as written would also require the Transmission Owner to notify itself. Therefore, suggest revising R2 and M2 as follows: R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the "other" owners of those Elements… M2. The Transmission Owner has dated evidence (electronic or hardcopy) of notification to "other" owners of Elements… Requirement R3 specifically asks to have SOER, however the guideline for R3 allows for the breaker status to be determined by analysis of suitably time synchronized FRs with the data provided in the manner detailed in R4. This should be identified in the Requirement itself. The guideline is a non-binding portion of a standard. The guideline for R3 has a typo (it should reference R4 instead of R14). Requirement R4 is not clear if determine means that the required BES Elements of TO and GO shall have waveforms for each phase current and the residual or neutral current. Regarding Requirement R4, Part 4.2, it is not clear if only high-side voltage winding voltages and currents need to be recorded. Clarification is needed if low-side voltage windings and transformer neutral need to be monitored also. Part 4.1- More specificity is needed in the requirement. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads – "…. Voltages for each phase of either each line or bus." which could be confusing. Part 4.2 – Residual current and neutral current

are two different quantities. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This wording should probably be more specific by stating if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the Drafting Team). Sub-Part 4.2.1 – Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific. M4 (1): add “plus evidence the device was commissioned at the specific bus in question”. In Part 5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the requirement. We suggest R5.1 be reworded to say “A single record or multiple records that include at least one of the following:”. Part 5.1 – the two bullet items in this requirement are confusing and should be reworded to clarify what is intended. Part 5.1 Bullet 2- The wording should be changed as follows: “At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder.” Because the deployment of Fault Recorders are not required on every BES bus, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it is occurring more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it. Part 5.2 assumes that SOE recording is driven by DFR analog sampling since it infers the achievement of a 1ms digital event resolution for a 960Hz (16x60Hz) analog sample rate. Stating analog and event resolution requirements (i.e. 16 samples per cycle and 1ms event resolution respectively) separately and explicitly is clearer and accommodates instances where SOER is separate from analog sampling. Part 5.3.1. asks to have trigger settings for neutral (residual) overcurrent, which implies for R4 that it is necessary not only to determine but to monitor either each phase current or neutral current. Regarding requirement R6, the standard should not create a new term like “Responsible Entity” but should only refer to specific NERC entities like TO, GO, RC, etc. If the Drafting Team decides to retain sub-Part 6.1.6, then it is recommended the phrase "all Elements associated with Interconnection Reliability Operating Limits" be replaced with "elements critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" similar to the language used in CIP-002-4. CIP-002-4 - Attachment 1 Critical Asset Criteria reads: 1.8. Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies. There is an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The Drafting Team has mapped this requirement to R14 of PRC-002-2. These two activities are not the same since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. R14 of PRC-002-2 requires entities to repair equipment that they know is in a failed state. The Part 8.3 wording is too restrictive. Real and reactive power may not be able to be determined operationally if say a bus is split at the time of an event (or the split is caused by an event). Suggest the Drafting Team correct this requirement by referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions Real and Reactive Power could be determined. The design should be assuming all normally-closed circuit breakers on a bus are closed. This avoids being out of compliance during a specific event, if open bus breakers preclude recording the MVA flows on all elements. Requirement R10 should allow the legacy equipment to have multiple triggered records which make up the required length. It is stated that triggered records from existing equipment can be accepted in lieu of continuous recording if the triggered records meet the criteria in 10.1 and 10.2. If continuous recording is available and meet all criteria, are triggered DDR records required? R13 – this requirement places the RC, RE and/or NERC in the middle of data sharing. There is no requirement in the standard to facilitate entities to partake in data sharing. Is this really the intent? What if adjacent entities need to exchange post-disturbance information? Does that really need to occur via the RC, RE or NERC if an entity cannot directly request necessary data? Requirement R13, Part 13.3. asks for SOER data in Comma Separated Value (.CSV) format whereas the majority of Disturbance Monitoring Equipment (DME) do not save data in this format. In addition, if breaker open/close position determination from FR data is acceptable, no .CSV file can be created by the recording tool itself. There is no need to require this data to be written in CSV format. Tab delimited text would work as well and would not limit the use of commas in descriptors or other entries. The format described in Attachment 2 is limiting and incomplete (see comments on

Attachment 2 below). Similarly, R13 Part 13.4. asks for FR and DDR data in C37.111 , IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files whereas the majority of DME equipment does not save data in this format. Are manually converted records acceptable? This requires that Fault Recording and Disturbance Recording data will be provided in COMTRADE (C37.111) formatted files, but does not specify a revision level or year for the COMTRADE standard. The requirement should specify “C37.111-2013 or later” in order to require a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data. In R14, reword to indicate that the second bullet is only applicable if the first bullet is not completed within 90 days. We suggest this wording for the second bullet – “If recording ability is not restored within 90 days, report the inability...” The Rationale for requirement R14 recognizes that the DME equipment cannot be always returned to service within 90 calendar days of the discovery of a failure. Requirement R14 itself, however, is not clear and should be rewritten to reflect that. PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Regarding Attachment 2, the format in Attachment 2 is limited and incomplete. While the information required is obviously necessary, the format limits or omits information available from some SOERs. R13.3 states that the files must be comma-delimited, but Attachment 2 makes no statement about the length of any string or value. There is no provision for SOERs which may have detailed descriptors of the contacts being monitored but may be a single string. “Local Time Offset from UTC” should be expressed in hours before or after UTC rather than letter designations. There is no provision for acceptable terms for “State” except for “OPEN “and “CLOSE”. Other terms may be more appropriate for some devices monitored by an SOER, such as “ENABLED” or “DISABLED”, “ON” or “OFF”, etc. In short, Attachment 2 appears to be an attempt at defining a standard but does not adequately define a format. Development of such a standard may be better left to an IEEE Working Group or other entity.
Group
North American Generator Forum - Standards Review Team (NAGF-SRT)
Allen Schriver
Yes
No
Modify the applicability section 4.3 by adding the following parenthetical after Generator Owner: (“Applies to GO only if GO owns a generator output breaker in the TO’s system”) We made the comment in the 11/19/13 webinar that DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data, GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording and storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. The webinar presenters stated that this would make TOs responsible for monitoring GO equipment, and there is no technical reason for making them do so. We disagree in that disturbances do not originate exclusively in generation plants, and the majority of such events may in fact stem from transmission system problems (as was the case for the Northeast blackout of ’03). That is, one can just as easily say that R9 makes GOs responsible for monitoring reactions to the TO’s system, and there is no technical reason for making GOs do so. Given this inability to establish a universal cause-vs-effect rule for disturbances the least-total-cost approach should be followed, and centralizing DME makes more sense than splitting it between involved entities (TOs) and those who merely hand-over recordings (GOs). This point was made again in the 12/5/13 NAGF outreach WebEx meeting, and there did not appear to be a strong rationale for having GOs be designated Responsible Entities when they in fact would be mere appendages, i.e. installing what are to them black boxes and handing-over recordings that they don’t understand.

No
Disagree. Smaller generators who may be drawn into the standard are likely to have only one location to install equipment. This would require 100% compliance within 2 years of notification. If notification occurs soon after a major outage, the generator may be forced to take an unneeded outage just to comply with the standard. Suggest adding the following: For entities with fewer than four locations identified by the TO, entity shall be 100% compliant within four years with no compliance required prior to that date.
1. It appeared from the 11/19/13 webinar that the R9 obligation for GO's to "have" DDR does not mean that they must own such equipment, and this position was confirmed in the 12/5/13 NAGF outreach meeting. That is, it would do just as well to have an agreement with the TO to fulfill the PRC-002 requirements if and where the TO already has DDR on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002. R9 should have a footnote saying that "This standard defines the 'what' of DDR, not the 'how.' GOs may install this equipment or, where the TO already has suitable DDR, contract with the TO." It would be still better to just drop GOs from the picture, however, per our comment to question #3 above. Additionally, it is not clear in R9 whether the specification for signal measurements is on a per generating unit basis or if the signals of interest are a per line basis aggregate at generating stations. Please more clearly specify if the signals of interest are individual unit measurements or plant total measurement (grouped by output circuit, plant total, etc.). This determination weighs heavily on the cost and method of implementation where new equipment must be installed. 2. R6 sets DDR applicability criteria based on the "nameplate rating," but doesn't say of what. This could be the generator, or the most-limiting component. We believe that applicability should be based on the most-limiting component, since this sets the actual output achievable. The term, "Facility Rating," as defined in FAC-008 should then be used to avoid confusion. 3. The frequency and Hz/s settings of R10 should have a latch-time criterion, to prevent spurious triggering of the DME. We suggest three cycles. 4. R10 calls for DME to be triggered at no lower than 85% of normal voltage with a latch-time of 5 seconds, but the 5-second ride-through requirement of PRC-024 is only +/- 10%, which is also often where V/Hz relays are set. A trigger of 85% voltage x 5 sec may therefore cause DME to miss the action. Additionally, R10 allows the use of triggered records from equipment installed prior to the effective date of PRC-002-2, but does not specify how many records an entity must be able to produce in the retrievable period specified in R13 as 10 days prior to a request. This specification is crucial to the amount of memory requirements of existing equipment. At the maximum trigger frequency (triggering every 3 minutes), the existing equipment becomes effectively a continuous recorder. For existing equipment with triggered recording capability, how many records are required to be available in the 10 day retrievable record.
Individual
Rick Terrill
Luminant Generation Company LLC
Yes
Yes
Requirement R4 as written could require both the Transmission Owner and the Generator Owner to monitor the requested electrical quantities for all lines and elements at the bus or switchyard where the generator is interconnected. R4 needs to be re-written to clarify that the GO is only responsible for monitoring for faults on the equipment it owns and the same for the TO. For Requirement R13, subsections 13.3, 13.4 and 13.5 should be deleted from the standard entirely. These items are completely administrative in nature and are not results based. An entity could make a typo mistake

in formatting or when naming a file and be non-compliant with the requirement. Also, the sub-requirements reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. Finally, the standard is written in a confusing format where twelve of the 14 requirements in the standard reference other requirements, which in many cases reference another requirement (or two). As a GO, I need to know, in a clear concise manner, what electrical quantities or status I need to monitor where, and what attributes are needed for the disturbance monitoring equipment
Group
Hydro One Networks Inc.
Sasa Maljukan
No
The definition for SOER optionally includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit breaker position. The purpose of the standard is to “have adequate data available to facilitate analysis of BES disturbances”. We don’t see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis.
No
This requirement (and associated Attachment 1) requires some clarity before we can determine if we agree with the methodology. This may be a bit problematic with the BES definition not confined to busses. What is a BES bus location? Does this mean the entity gathers information on all fault levels for busses which contain at least one BES Element?
Yes
No
1. R6.1.4, first bullet – Requiring monitoring of all “Flowgates” on the Eastern Interconnection seems arbitrary and diminishes the role of those with the best understanding of the nature of their system to determine the appropriate locations for DDRs. The guideline for R6 included in the draft fails to explain why all flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the maximum precontingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with the requirement R6.1.3.2 since there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. 2. Requirement R6.1.5 - This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities 3. Requirement R6.1.6 - The guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLs) should be monitored. The NERC lists including all elements associated with IROLs are very extensive. This requirement will increase the number of the DDRs need to be installed exponentially.
Yes
Yes
1. R5.1 Bullet 2- The wording should be changed as follows: “At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder.” Because the deployment of Fault Recorders are not required on every BES bus location, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it is occurring more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not

directly monitoring it. 2. R4.1- More specificity is needed in the requirement. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads – “.... Voltages for each phase of either each line or bus.” which could be confusing. 3. R4.2 – Residual current and neutral current are two different things. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This wording should probably be more specific by stating if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the DT). 4. R4.2.1 – Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific. 5. There is an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The DT has mapped this requirement to R14 of PRC-002-2. These two activities are not the same at all since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. In fact preventative maintenance should reduce the failures. R14 of PRC-002-2 requires entities to repair equipment that they know are in a failed state. 6. R13 – this requirement places the RC, RE and/or NERC in the middle of data sharing. There is no requirement in the standard to facilitate entities to partake in data sharing. Is this really the intent? What if adjacent entities need to exchange post-disturbance information? Does that really need to occur via the RC, RE or NERC if an entity cannot directly request necessary data? 7. R8.3 wording is too restrictive. Real and reactive power may not be able to be determined operationally if say a bus is split at the time of an event (or the split is caused by an event). Suggest the DT correct this requirement by perhaps referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions, Real and Reactive Power could be determined. 8. R3, R4, R12, R13, R14 all reference “the bus locations as per Requirement R2” however this requirement is a notification requirement only for Elements not owned by the TO that need DME. These requirements need to reference both R1 and R2 pending changes to R1/R2. 9. The way R2 is worded presently, it sounds like a TO is required to notify itself if it owns BES Elements at the bus locations. The only action in R1 is to identify busses for DME. It should probably be expanded to indicate that after the busses are identified the TO needs to have DME on the Elements that are owned by the same TO. 10. R3, R4, R12, R13, R14: List of locations that need Sequence of Events Recorders and Fault Recorders is identified in R1 and communicated in R2. Suggest replacing reference to R2 with R1 11. R8,9,10,11 and R13, R14: Suggest changing reference to R7 with R6 (see the comment for R3 and R4 above) 12. Section 1.2 - Evidence Retention: Second sentence states:” For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.” . To avoid confusion we recommend that the SDT removes “may ask” and provide further clarification on what evidence needs to be retained and for how long. One approach would be to make a retention period to be “greater or longer of” the period since the last audit or the list below. 13. Section 1.2 - Evidence Retention: To avoid confusion we suggest that the retention period for R1/R2 and R6/R7 is specified as “current version of the list” or “current and previous version of the list”. This will avoid confusion associated with the five years retention when the list is produced at a 5 year cycle.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
No
1. DDR definition: The phrase "abnormal voltage problems" is redundant. Suggest definition be changed to: The recording of time sequenced data for dynamic power system characteristics such as power swings, frequency variations, or abnormal voltage conditions. 2. SOER definition: Need to specifically identify circuit breakers, which are the primary Elements needed for SOER as indicated in Requirement 3. Suggest it be changed to: The recording of time sequenced data for change in status of Elements, particularly circuit breakers, and including other protection and control devices as needed.
Yes

Yes
Yes
No
Item 5 This item references a nine month timeframe associated with R14. There does not appear to be any such timeframe listed under R14. Since the required in-service dates for DME are from two to four years, that timeframe should determine the compliance date for R14.
In Requirement 14, there is a discrepancy between the text of R14 and the Rationale statement which follows. The bullet “Restore the recording capability” should be changed to “Restore the recording capability if possible”. This will allow the entity more time if necessary to correct the problem, which is allowable as described in the Rationale. As it stands, an entity will be in violation if the recording capability is not restored within 90 days of discovery of a failure.
Individual
Kayleigh Wilkerson
Lincoln Electric System
LES recommends the drafting team further clarify the bus selection process included in Attachment 1. As drafted, the current Attachment 1 methodology does not appear to account for substation configurations such as a 115kV tap bus with a radial transformer fed from that bus. Although the radial transformer would not be considered a BES Element, the bus would be considered BES since it carries through-flow on the line. At this substation, there is no relaying and therefore no capability for SEOR or FR. In consideration of this, does the drafting team intend for this type of bus to be included on the list? By including these busses, the total number of busses, and therefore the total number of substations requiring SEOR and FR, would increase considerably for some entities.
R13.2 specifies that “The recorded data will be retrievable for the period of 10 calendar days preceding a request”. As drafted, this requirement seems to indicate that if an event happened on June 1st and the data was requested on June 30th, then the data would have to be retrievable from June 20th to the 30th. However, if a request is made on June 6th following a June 1st disturbance, it would not be possible to comply with the 10 calendar day requirement. Unless LES misunderstands the drafting team’s intent, it seems as though the requirement is meant to ensure that data is available and retrievable for a period of 10 calendar days following a disturbance in the event further analysis needs to be conducted. To ensure this intent is conveyed, LES recommends rewording R13.2 to indicate that the 10 day period starts at the time of the event. Additionally, R13.2 should also account for circumstances beyond the control of the TO or GO in which multiple events caused the relays recording the data to overwrite it with more recent events due to limited memory space. As an example, a TO could have information available for the 10 days required by the standard, but multiple disturbances due to severe weather on day 12 resulted in initial data being unavailable for a request initiated on day 12 or later. If this occurs, R13.2 would then place the Transmission Owner or Generator Owner in violation of the standard due to a limitation inherent to the relay. 13.2. The recorded data will be retrievable for the period of 10 calendar days following a disturbance.(1) Footnote (1): The 10 calendar day period may be waived for circumstances beyond the control of an applicable Transmission Owner or an applicable Generator Owner, such as, but not limited to, equipment manufacturer limitations resulting in the loss of data.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.

Agree
NPCC
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
We agree with R1, but we do not see the need for R2 since through R1 and Attachment 1, each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR). There is not another owner(s) that a TO needs to communication the list to, unless the "list of BES bus locations that it owns" depicted in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that's the case, Step 1 in Attachment 1 needs to be clarified.
Yes
No
R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but Part 6.1.1 and 6.1.2 are not criteria for "Elements", but rather, they are criteria based on demand size and footprint. It would be helpful if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., Pats 6.1.1 and 6.1.2), and one for the location/element (Parts 6.1.3 to 6.1.6). Requirement R6.1.4 - The guideline for R6 included in the draft fails to explain why all flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the maximum precontingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with the requirement R6.1.3.2 since there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. Requirement R6.1.5 - This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities. Requirement R6.1.6 - The guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLs) should be monitored. The NERC lists including all elements associated with IROLs are very extensive. This requirement will increase the number of the DDRs need to be installed exponentially.
Yes
Yes
Individual
Bill Fowler
City of Tallahassee (TAL)
Yes
Yes
Yes
Yes

Yes
Yes
Individual
Thomas Foltz
American Electric Power
No
Sequence of Events Recording (SOER) – This definition should only specify functionality and *not* attempt to define scope. Instead, we suggest “The recording of time sequenced data for change in status of a monitored, binary value”. Fault Recording (FR) – Again, this definition should only specify functionality and *not* attempt to define scope. Instead, we suggest “The recording of time-sequenced waveform data for a monitored analog value.”
No
Fault analysis programs such as ASPEN include tap busses to provide connection points for distribution transformers, series capacitors, three-terminal lines, etc. Since these connection points do not have circuit breakers associated with them they are not appropriate locations for disturbance monitoring. However, when applying the Attachment 1 process, these tap busses could show up and possibly distort the Attachment 1 data. The fault summary feature in ASPEN has a check box to ignore tap busses. AEP requests that this feature be utilized in the Attachment 1 process. AEP is concerned that the “top 10%” requirement could force the installation of fault recording devices to be installed at a station with only 2 BES sources. An example is a protected load bus with only 2 BES elements that is connected to stations which meet the requirement and have fault recording devices installed. In this case, both of the stations remote to the protected load bus are BES buses in the top 10% of a TO’s bus listing. The standard should not require DFR/SER at those locations. AEP’s position is that the standard should focus on fault information availability after an event that allows for accurate analysis and not on over-saturation of fault recording equipment that will require monitoring and maintenance to ensure that the equipment is in service when needed. R2 states that TOs must notify owners of Elements that those elements require SOER/FR. However, the process identified in R1 does not establish a requirement to identify BES Elements. This does not account for the fact that not all elements on the identified busses should require SOER/FR. AEP suggests that the SDT add a new R1.3 to state “For each bus identified per 1.1, the Transmission Owner shall identify the BES elements that require FR and the BES interrupting devices that require SOER”. The draft can be interpreted to require TOs to dictate to GOs and IPPs where they must install FR/SOER. AEP believes it would be inappropriate for TOs to specify FR/SOER locations for GOs and IPPs. While Attachment 1 provides a reasonable method for TOs to produce a list of buses that it owns, R2 will make TOs responsible to keep track of elements within those buses that it does not own. This responsibility should be revised so that TOs can focus on ensuring that they have adequate equipment in place to monitor its system, rather than managing the complex logistics needed to notify GOs and IPPs.
Yes
No
This listing appears far too prescriptive by going beyond the “what’s” and specifying the “how’s”. In the application of R6, the Responsible Entity should consider existing DDR installations when determining where to require DDR. There may be existing installations that can satisfy the R6 criteria. At a minimum, it might be beneficial to add such considerations to the “Guideline for Requirement R6” section. It is unclear whether DDR is required on all generating resources or only some generating resources that meet the requirements of R6.1.3.1 and R6.1.3.2. We suggest changing the title of Section 6.1.3 to “All generating resources with:” to be consistent with the other sections.
Yes

No
We believe the implementation plan will be sufficient, however we cannot state that with absolute certainty until the completion of the identification processes in R1 and R6. At this time, the actual scope is still unknown.
In general, we believe the standard is written to prescriptively when the standard emphasizes post-event analysis. More clarity is needed regarding time frame, etc. as to what is expected of a TO after they informed that data recording is required for an element owed by the TO. R13.1: Suggest "The recorded data will be provided within 30 calendar days, or other agreed-upon timeframe, of a request." It appears that R2 applies to shared stations only. If this is accurate, we suggest rewording to clarify the intended applicability. In addition, it is unclear which entity would be responsible for the installations. The wording in R13.2 is unclear. Possible interpretations include that the data must be retrievable for at least 10 days at any given time, or that the data must be retrievable on a continuous basis. Please revise to provide clarification. The sub-bullets listed in R13, especially R13.2, would be more appropriately included in the technical requirements of each DME type in R3, R5 and R11. The sub-bullets in R14 read do not clearly read as an OR statement and may be misinterpreted as an AND statement. We recommend removing the bullets and making the item read as a single sentence: "… shall restore the recording ability or report the inability to record data…" R3 requires GOs and TOs to install SOER for each circuit breaker they own that is connected to the bus locations identified in R1. This does not account for the fact that not all of the circuit breakers on the identified busses should require SOER because some breakers may be associated with non BES equipment. R4.1 should be modified to state "Phase-to-neutral voltages for each phase of either each specified line or bus." In R5.1, an "or" should be added to the end of the first bullet to improve clarity. Also, in R5.3 the word "settings" should be removed to improve technical accuracy. In R7, the word "determination" should be replaced with "identification" to be consistent with the rest of the standard. R8 should be revised as follows to improve clarity: R8.1: "At least one phase…" R8.2: "The current on the same phase as the voltage in…" R8.4: "Frequency of at least one of the…. R9 should be revised as follows to improve clarity: R9.1: "At least one phase…" R9.2: "The phase current on the same phase as the voltage in…" The drafting team may want consider combining requirements that are related to the same monitoring equipment types. R4 and R5 could be combined because they both relate to specifications of FR equipment. Similarly, R8, R10, and R11 could be combined, as they all relate to DDR equipment.
Individual
Scott Langston
City of Tallahassee
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Kathleen Goodman
ISO New England Inc.

No
Comment on R6 – The standard should not use the term “Responsible Entity” but should only refer to specific NERC entities like TO, GO, RC, etc. Comment on R6.1.4 –Requiring monitoring of all Elements of “Flowgates” on the Eastern Interconnection seems arbitrary and may miss important locations for DDRs, especially for areas that do not use flowgates. If “Flowgate” monitoring is required, this item should include a link to the official list of NERC Flowgates so that the “Responsible Entity” knows where they need to install DDRs. This requirement will also lead to installation of equipment that provides practically no value to the Purpose of this standard. For example, the NY-NE interface is one of the official NERC Flowgates, which means that ISO-NE will need a DDR at each of eight stations that interconnect with New York; NYISO will need to do the same and lead to the installation of unnecessary, redundant equipment. DDR location requirements for ERCOT, Hydro-Quebec, and the Western Interconnection do not define major transmission interfaces or major transfer paths, allowing for arbitrary interpretation. Also, for the Western Interconnection, responsibility is placed on the “Regional Entity” and not a “Responsible Entity” like the Reliability Coordinator or Planning Coordinator. Comment on R6.1.5 – this will require Reliability or Planning Coordinators to call for the installation of DDRs at HVDC facilities that are smaller than the generator requirement listed in R6.1.3 (500 MW). If this requirement is retained, it should be specify “… HVDC facilities greater than 500 MW…” Comment on R6.1.6 – This requirement could lead to installation of DDRs at many, many substations in New England just to capture one flow or voltage that is part of an IROL. Also, DDR data is of little value for IROLs that are thermal in nature. General comment on 6.1.3 through 6.1.7: The level of detail specified in these items eliminates the role of the RC/PC who are best able to determine appropriate locations for DDRs. This requirement should recommend locations and not attempt to precisely specify where DDRs should be installed. These requirements could be rephrases as follows: “The RC/PC shall specify DDR locations that serve the Purpose of this standard (To have adequate data available to facilitate event analysis of BES disturbances). The RC/PC should consider specifying locations that include generators and HVDC facilities greater than 500 MW, major transmission interfaces, transfer paths, flowgates, voltage sensitive areas…”
No
The VSL for R6 calls for the Reliability Coordinator or Planning Coordinator to have “accurately identified the Elements for DDR as directed by Requirement R6”. The term “accurately” should be deleted.
No
Installation of potentially 200 additional DDRs will take far longer than the time specified in the Implementation Plan.
Requirement R5.1 currently reads: 5.1. A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault. Comment R5.1 – the two bullet items in this requirement are confusing/conflicting and should be reworded to clarify what is intended. I.E. is it 50 cycles per bullet 1 or three cycles per bullet 2? This is probably for single and multiple records but the language should identify the difference as shown below. • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. (Single Record Only) • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault. (Multiple Records Only) Comment on R13, this requirement could place the Reliability Coordinator/Planning Coordinator in the middle of data sharing. This requirement should encourage direct sharing of data. Also, R13.3 and Attachment 2 attempts to define yet another format for SOE data; There are well established formats for this type of data, such as COMTRADE, that include many other aspects of data such as file and signal naming conventions.
Individual
David Kiguel
N/A
No

The proposed definition of SOER indicates that it may include protection and control devices. However, R3 only specifies the recording of circuit breaker position (open/close). The purpose of the standard is to “have adequate data available to facilitate analysis of BES disturbances.” In order to permit for a comprehensive analysis of disturbances some basic protection device information is necessary and should not be optional in the definition. I suggest replacing “may include” with “includes.”
Yes
No
1. Requirement R6.1.5 – Consideration should be given to address the case when the ends of HVDC terminals (back-to-back or each terminal of a DC circuit) on the AC portion of the converter are owned by different entities 2. Requirement R6.1.6 – Justification should be provided on the technical justification for all Elements associated with IROLs to be monitored. The NERC lists including all elements associated with IROLs are very extensive, thus significantly increasing the number of the DDRs that need to be installed.
Yes
Yes
The Drafting Team and NERC staff are to be commended for the work done, this being such a complex standard. They have taken the right approach by addressesing “what” (data) is to be captured, not “how” and by not considering Disturbance Monitoring equipment. However,additional work is needed to make this standard acceptable. 1. The way R2 is worded presently, it sounds like a TO is required to notify itself if it owns BES Elements at the bus locations. The only action in R1 should be to identify busses for DME, expanded to indicate that after the busses are identified the TO needs to have DME on the Elements that are owned by the same TO and notify such identification for the Elements owned by others, if any. 2. R4.1- As written, this requirement could be confusing. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads – “…. Voltages for each phase of either each line or bus.” which could be confusing. 3. R4.2 – Residual current and neutral current are two different things. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This requirement should specify that if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the DT). 4. R4.2.1 – Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific. 5. R5.1 Bullet 2- The wording should be changed as follows: “At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder.” Since the deployment of Fault Recorders is not required on every BES bus location, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it occurs more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it. 6. There seems to be an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The DT has mapped this requirement to R14 of PRC-002-2. These two activities are not the same at all since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. In fact preventative maintenance should reduce the failures. R14 of PRC-002-2 requires entities to repair equipment that they know are in a failed state. 7. Real and reactive power may not be able to be determined operationally if for example, a bus is split at the time of an event (or the split is caused by an event). Suggest the DT correct this requirement by perhaps referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions, Real and Reactive Power could be determined. 8. R3, R4, R12, R13, R14 all reference “the bus locations as per Requirement R2” however this requirement is a notification

requirement only for Elements not owned by the TO that need DME. These requirements need to refer to both R1 and R2. 9. R3, R4, R12, R13, R14: List of locations that need Sequence of Events Recorders and Fault Recorders is identified in R1 and communicated in R2. Suggest replacing reference to R2 with R1 10. R8,9,10,11 and R13, R14: Suggest changing reference to R7 with R6 (see the comment for R3 and R4 above).
Individual
Texas Reliability Entity
Texas Reliability Entity
Yes
In the definition of Dynamic Disturbance Recording, we would suggest including phasors in the list of power system characteristics. This would be useful in applying DDRs at locations where there may be angular stability concerns or subsynchronous resonance concerns.
Yes
(1) The SDT may want to consider different short-circuit MVA levels based on the voltage or voltage class, i.e. 1500 MVA for 100-200kV, 2500 MVA for >300kV, etc. (2) To insure broader system coverage, the SDT may also want to consider including some flexibility in the location criteria in Step 8 of Attachment 1, such as substations > 200kV with 3 or more non-radial line terminals, substations < 200kV with 5 or more non-radial line terminals.
Yes
Yes
(1) The SDT should clarify the meaning of "major transmission interfaces" in 6.1.4, as this is an undefined term that will lead to considerable debate about what a "major" interface is. (2) The SDT may also want to consider applying DDRs to Elements with a known angular stability issue or subsynchronous resonance issue that does not rise to the level of an IROL.
(1) For Requirements R2-R5 at substations where there are multiple Transmission Owners, are entities allowed to use a shared FR/SOER, or is each entity individually responsible for the Elements that they own? (2) For Requirement R14, there appears to be an "or" missing following the 1st bullet, "Restore the recording ability, or". The SDT may want to consider having the entity reporting DDR failures report to the Responsible Entity as well as the Regional Entity, so that the Responsible Entity can look at possible alternative methods to monitor the Elements required per R7.
Group
Seattle City Light
Paul Haase
Seattle City Light appreciates the effort of the drafting team in developing this proposed Standand, and understand the concept to focus requirement on data requirements rather than equipment requirements. That said, Seattle does not support this draft or approach. The draft is far too complex and technical to be an effective Federal regulation, in part because it requires a slow and cubmersome process to update each time a technical specification goes out of date. Seattle recommends that the Standard be revised to provide general requirements that are consistent over time, with details referenced in a separate document similar to the data collection and data preparation manuals associated with data-collection regulations in other areas (such as for regional

model development). Additionally, Seattle cannot support such a detailed and complex Standard until additional guidance is available about the compliance implications, such as an RSAW or guidance document.
Group
Reason International, Inc.
Lucas Oliveira
Yes
No
Several problems in the correct operation of protective measures are related as reflexes of unmitigated harmonics influencing the actuation of protective relays. Industrial plants with high nonlinearities and intense electric power consumption have large influence in the interconnection to the transmission system. The harmonic distortions introduced by these industrial plants range from low to very high orders, up to the 20th harmonic. These distortions may lead to measurement errors and the incorrect operation of protective relays. To avoid aliasing the sampling rate needed to analyze such events, capturing up to the 24th harmonic, should be 48 samples per cycle. Fault recording should therefore be carried out at a minimum of 48 points per cycle, above the typically used 16 points per cycle of protection algorithms.
Yes
No
Power swings are one of the most common and dangerous long-term disturbance events. They occur due to inadequate power flow conditions in a variety of states of the BES. These dangerous states may be reached through unforeseeable manual maneuvers or inadvertent automatic maneuvers during operation, as those occurring during an fault. Power swings may evolve to a system-wide failure, due to voltage dips, under- over-frequency, etc. To correct evaluate this situation it is necessary to compute the system power. Therefore, it's also necessary to monitor currents as well as voltages.
Yes
Yes
Attachment 2 provides a template for standardization of Sequence of Event records. Following the successful implementation of COMTRADE and recognizing the leading role the US BES plays internationally, it would be more beneficial to all parties involved if the template was based on C37.239-2010 COMFEDE, avoiding multiple templates for SOE records in several countries.
Group
ACES Standards Collaborators
Ben Engelby
No
We do not support the proposed definitions because these seem to be straightforward and understandable without proposing additional glossary terms. The Standards Drafting Team Guidelines, dated April 2009, states: “The SDT should avoid developing new definitions unless absolutely necessary. There is a glossary of terms that has been approved for use in reliability standards. Before a drafting team adds a new term, the team should check the latest version of the Glossary of Terms for Reliability Standards to determine if the same term, or a term with the same meaning, has already been defined. If a term is used in a standard and the term is defined in a collegiate dictionary, then there is no need to also include the term in the NERC Glossary of Reliability Terms. The addition of an adjective or a prefix to an already defined term should not result in a new defined term. It is very difficult to reach consensus on new terms. If a simple phrase can be used in a standard to replace a new term, then the drafting team should consider using the

phrase rather than trying to obtain stakeholder consensus on the new term." We do not see how these proposed terms are "absolutely necessary." Please provide a rationale why other approaches could not be taken.
No
We concur with the drafting team's observation and rationale that there is no need to monitor disturbances for small systems in the same manner as large systems. However, we believe this standard should require an entity to generate its own methodology that identifies how it will determine locations to install Fault Recording and Sequence of Events Recording devices and supporting equipment and how often it will conduct these assessments. We feel the method proposed for selecting bus locations is too restrictive and could be subject to interpretation from auditors when not properly followed.
No
(1) There is confusion over the Planning Coordinator and Reliability Coordinator functions and their respective relationships. As the standard is currently written, both the PC and the RC are subject to the standard in ERCOT? (2) We do not believe any function would benefit from the standard. Industry has already benefitted from the DOE grants to install PMUs and would continue to benefit from these types financial incentives to continue installing PMUs for situational awareness. The existing financial incentives have obviated the need for the standard as evidenced by report on the September 8, 2011 Arizona-California outages. There was sufficient data to analyze the event. NERC should develop a technical guideline on this topic instead of a standard.
No
We believe that Requirement R6 could be consolidated with other requirements and the detailed sub-requirements could be moved to an appendix. This would be more appropriate to model this standard like PRC-023-2, where the appendix provides important details but does not subject registered entities to violations for every sub-requirement.
No
We do not support the standard as written, as it should be consolidated into fewer requirements and should take a more streamlined approach. Since we do not support the standard, we cannot support the corresponding VRFs and VSLs.
No
The implementation plan is confusing. We do not see the need for a phased in plan, where some requirements are enforceable before others. Assuming standard continues to be developed which we do not support, we recommend consolidating the entire standard to two or three requirements and propose a straight forward implementation plan.
(1) This standard is unnecessary because there are already significant amounts of PMU data to construct sequence of events and other post-event analysis of disturbances. As referenced in the Southwest Blackout Report of 2011, there is a multitude of disturbance monitoring devices installed on the electric grid. The Southwest Blackout Report states, "PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP)." We do not see the cost benefit of requiring additional resources for an issue that is not a high priority for reliability. (2) As stated above, there are financial incentive programs through other federal agencies that provide funding for disturbance monitoring equipment. We recommend that NERC work with those programs to develop a technical guideline to ensure these devices are installed and monitoring critical areas of the electric system. (3) Why has the drafting team decided to include 14 requirements to this project? In light of recent standards projects like Paragraph 81, the industry is supporting reducing and consolidating the amount of requirements. We do not see the need to have 14 requirements for disturbance monitoring. While we do not believe the standard is needed, we strongly recommend that the drafting team revise this standard to two or three requirements if it persists. The amount of detail is unnecessary and poses a serious compliance burden on registered entities. (4) R2 requires implementation within ninety days of Fault Recording and Sequence of Events Recording devices following a notification provided by the Transmission Owner. We question if this will provide entities sufficient time to acquire such devices from their suppliers. Moreover, entities can be, from time-to-time, directed to suspend maintenance activities on their BES elements due to extreme weather conditions or more immediate system level emergencies. These entities plan their maintenance activities months in advance, only to have such activities delayed by days or weeks as necessary to maintain system reliability. We recommend

extending the period required within R2 to at least twelve months, as this should be sufficient time to acquire and install these recording devices during non-peak calendar dates. (5) We feel that R8 and R9 do not adequately accommodate joint substation facilities and shared resources. As stated, the burden to install Dynamic Disturbance Recording devices falls on each individual Transmission Owner and Generator Owner. Sharing such installations limits the number of connected measuring devices to facility structures, including current and potential transformers, further limiting the possibility that one of these measuring devices catastrophically fails and leads to a more significant impact on the facility's availability because they are jointly owned. (6) We previously commented that an appendix, modeled similarly like in Standard PRC-023-2, would be a better alternative to Requirement R6. Likewise, including details like those listed in R12 would further strengthen a case to incorporate this appendix in the Standard and not subject registered entities to possible violations for every requirement. We feel that technology has significantly improved since 2003, as manufacturers have supported the need to align such devices on a common frame of time. Still R12 places the burden on registered entity, when it seems more appropriate to be included in a manufacturer technical specification. (7) We feel Requirement R13 is arbitrary, could be subject to interpretation from auditors and meets paragraph 81 criteria. Transmission Owners and Generator Owners could be required to prove the negative, and demonstrate that they have not received a request to provide device data to their Reliability Coordinators, Regional Entities, and NERC. Furthermore, this standard meets several Paragraph 81 criteria including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. The requirement is administrative because it compels data formats that are immaterial to reliability with the sole purpose to simplify data collection and communication. It meets the data collection/data retention criterion because the requirement is about collecting data. It also meets the reporting criterion because it compels data reporting. Please strike the requirement in its entirety. It would be more appropriate to include in a guideline. (8) We believe numerous requirements of this Standards fall under Paragraph 81 Criteria B, and are thus unnecessary. For instance, we feel requirements R1.2 and R6.2 are "Periodic Updates" due to the need to reassess each list every five calendar years. Likewise, we feel requirements R2, R7, and R13 are "Administrative" due to the need to collect, organize, format, and then circulate data and communications sent to identified entities within a specific timeframe. We feel that several other requirements could be "Data Collection" in nature. Requirements R5.1, R5.2 require the collection of data according to specifications outlined for the minimum recording rate and data duration. Requirements R10.1 and R10.2 require the collection of data according to specifications outlined for the trigger record lengths and trigger settings. Likewise, Requirements R11.1 and R11.2 require the collection of data according to specifications outlined for input sampling rate and output recording rate. Requirement R12 require the collection of data according to specifications outlined for time synchronization. Finally, Requirement R14 is "Administrative" and "Documentation" in nature based on the need to circulate the discovery of device failure within a specific timeframe and provide a Corrective Action Plan to the Regional Entity if repair is outside this timeframe. (9) The costs of installing new equipment for disturbance monitoring could be significant for our members. We find this standard is unnecessary and NERC should work with the Department of Energy (DOE) to further expand the use of grant money to supply registered entities with funding for these types of monitoring equipment. The prior grants from the DOE have been very successful and we see no reason to require these monitoring devices to be subject to enforceable reliability standards. There is no convincing evidence that these standards are being developed to address a reliability need. We see no justification for industry to allocate resources to disturbance monitoring equipment when there are other priorities that should be addressed first, such as cyber security. Furthermore, the joint NERC and FERC report on the September 8, 2011 outage in Arizona and southern California further demonstrates that there is not a need for the standard. It stated that there was ample event data that was recorded and used to analyze the event. (10) We appreciate the opportunity to comment on the cost of developing this standard (CEAP process). However, the timeline of submitting comments should align with the ballot and comment deadlines. It is unreasonable to set the comment deadline for the CEAP two weeks before the project comment deadline, considering the due date is Monday following Thanksgiving. We are concerned that industry was not aware of this deadline and did not have adequate time to prepare comments. (11) Thank you for the opportunity to comment.
Individual
Shirley Mayadewi

Manitoba Hydro
Yes
No
The intent of the methodology is good and will help TOs in determining the number of DMEs required. However, the application of the methodology using the provided "Median_Method_Template" is quite cumbersome and could be simplified.
Yes
Yes
Yes
No
The times for meeting requirements R1 and R6 are adequate. However, the time of 9 months required for complying with requirements R2, R7 and R14 is too short, especially considering that R14 may require troubleshooting, testing, shipping, repairs, possible replacement of the failed FR, SOER or DDR, possible discussions with suppliers, design and drawing considerations if the replacement is not identical, etc. Given the existing demands on maintenance and design staff, and the need to also develop a corrective action plan for the Regional Entity, the SDT should consider extending this time.
(1) An acronym is given for each of Sequence of Events Recording (SOER) and Fault Recording (FR) and Dynamic Disturbance Recording (DDR) but the acronyms are never used, and sometimes the full phrase is used without the acronym noted. This occurs throughout the standard and should be made consistent and cleaned up. If the acronyms are not going to be used, there is no need to state them. (2) R1, 1.2 - would be clearer to state 'identified bus locations should be reassessed at least once every five calendar years'. (3) M1 (same applies for all measures) - should be written to say that the entity 'shall have' not 'has'. (4) M1 - the last few words of the measure that deal with 1.2 are not complete - 'assessed within the required interval' should be 'and evidence that the identified bus locations have been reassessed within the required interval'. (5) R2 - would be more consistent with the rest of the standard to refer to 'BES bus locations' rather than 'locations' and 'identified' instead of 'established' and 'identification' instead of 'determination'. (6) M2 - would be more consistent to say 'BES Elements' rather than just 'Elements' and 'at the BES bus locations identified' as opposed to 'established' and 'notice' instead of 'information'. The measure is also missing the timeframe. (7) R3/M3/R4 - the reference to Requirement R2 does not seem correct in this context - should be those BES bus locations identified in R1? (8) M3 - the description of the circuit breaker position in M3 is lacking specificity that appears in requirement - '(open/close) for each.....' (9) R4 - for consistency, 'bus locations' should be 'BES bus location' and 'as per' should be 'identified in'. (10) R6, 6.2 - would be clearer to state 'the identified BES Elements shall be reassessed at least once every five calendar years'. (11) M6 - would be more complete to state 'The Responsible Entity shall have a dated (electronic or hard copy) list of BES Elements for which Dynamic Disturbance Recording (DDR) is required as identified in accordance with Requirement R6 and evidence that such identified BES Elements have been reassessed within the required interval.' (12) R7 - reference to 'the locations' needs to be more specific - is this the 'BES bus locations'? To be consistent, 'Elements' should be 'BES Elements' and 'established in' should be 'identified in'. (13) M7 - would be clearer if reference to 'owners' was to 'each Transmission Owner and Generator Owner'. 'established' should be 'identified' to be consistent. (14) R8 - 'Element' should be 'BES Element'. The words 'for which they received notification' could be added after 'own'. (15) R9 - same comments as R8 (16) R10 - the reference to R7 does not seem correct - is this meant to be R8 or R9 as it is these parts that put obligation on the TO and GO, whereas R7 puts an obligation on a responsible entity? Reference to 'equipment' seems vague - is this DDR equipment? (17) M10 - reference to 'data recording' should be to DDR? (18) R11 - as above, the reference to R7 does not seem correct - should be R8 or R9? 'Element' should be 'BES Element'. (19) R12 - as above, reference to R7 should be to R8 or 9? 'Element' should be 'BES Element', 'bus locations' should be 'BES bus locations' and

the word 'identified pursuant to' should replace 'as per' to be consistent. (20) R13 - same comments as R12. (21) M13 - the words 'data was submitted' should be replaced with 'that SOER, FR and DDR data was provided to the Reliability Coordinator, Regional Entity or NERC upon request'. (22) R14 - same comments as R12.
Group
MRO NSRF
Russel Mountjoy
Yes
No
For R1 – Add wording that would only obligate each Transmission Owner to identify BES bus locations where it owns Elements with wording like, ". . . Each Transmission Owner shall identify BES bus locations where it owns Elements . . ."
Yes
Please see question 7.
No
Note that R6 clearly states where DDRs are required where the intent of this Standard was for "data" and not devices. The SDT has presented mixed signals to the industry, please clarify. In R6.1.2., it states that at least one DDR location in each Responsible Entity's footprint. It is not clear if this means the Responsible Entities listed in R6 or the Responsible Entities listed in the Applicability Section 4. Does the Planning Coordinator or Reliability Coordinator, (as applicable) identify BES Elements for which DDR is required in the footprint of each Transmission Owner and Generator Owner or in their own respective footprints? R6.1.2. should be clarified to read "Each Planning Coordinator or Reliability Coordinator, (as applicable) is required to have at least one DDR in their footprint."
No
According to the Implementation Plan, the STD makes it clear that this Standard reflects the need for data, not the equipment used to collect the data. In addition, the SDT has already identified that there is already a significant amount of SOER, FR, and DDR equipment currently employed on the BES. The NSRF wants to point out that Section 215 of the Federal Power Act states that the ERO cannot order the construction of additional generation or transmission assets. The NSRF views the purchasing of equipment to provide "data" as construction. The Implementation Plan states that Generator Owners and Transmission Owners may be required to schedule outages to install or implement SOER, FR, and DDR equipment. Installing or implementing of SOER, FR, and DDR equipment is construction because it changes the current equipment configuration to a different configuration. To build on this point, Requirement 12 has the requirement to synchronize the time element. We believe this can only happen with some sort of satellite clock/ gps device, requiring the purchase of said additional device.
The NSRF believes that this Standard should apply only to those devices already installed by the Generator Owners and Transmission Owners on BES Elements. The SDT has already made it clear that there is an abundance of these devices on the BES. Therefore, a footnote should be added that the Registered Entities are not required to spend the ratepayers' money to buy new equipment to satisfy the requirements of this Standard. The NSRF proposes it should read "Each Transmission Owner and Generator Owner is not required to have Dynamic Disturbance Recording, Fault Recording, or Sequence of Events Recording devices which capture the essential data of PRC-002-2, installed or activated on its BES Elements." This would be incredibly comparable to footnote 1 of the industry-approved NERC Standard PRC-024-1. That footnote states "Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit."

Group
Dominion
Mike Garton
Yes
We could support the definitions as used within this standard but do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should be given to using the word “data” in place of the word “recording”, such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD. Also the definition of SOER presently uses the phrase “… status of Elements, which may include protection and control devices.” We recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status.
Yes
Yes
Yes
However, clarity is needed under 6.1.3 to understand how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples will be most helpful. Also clarity is needed in requirement 6.1.4 when you refer to “monitor all Elements of: all permanent flowgates”. If a flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every transformer need to be monitored (lowside or highside side)? Please show some typical examples. Also, under requirement 6.1, it may be better to move the minimum quantities requirements 6.1.1 (minimum 1 DDR per 3000m MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the requirements for 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc…), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable requirements, and state that additional DDR locations are only needed if fulfilling the first 5 does not meet the two extra minimum quantities requirements.
No
Recommend updating the “entity” for the following requirements on the Implementation Plan Summary: R8 – TO R9 – GO R10 – TO/GO
PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01). Dominion believes the intent of Requirement R2 is for Transmission Owners to notify “other” owners of BES Elements, as explained in the Rationale statement. The requirement as written would also require the Transmission Owner to notify itself. Therefore, Dominion suggests revising R2 and M2 as follows: R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the “other” owners of those Elements… M2. The Transmission Owner has dated evidence (electronic or hardcopy) of notification to “other” owners of Elements… In R1.2 and R 6.2, what prevents a TO or RE from assessing the locations and elements on too frequent of a time basis. As written, it provides no clause to prevent excessively short re-

assessment periods. There should be some minimum time (say several years) between assessments to provide stability in where monitoring is really needed. Frequent assessments could jockey locations above and below the minimum criteria line and create confusion. In R2, it infers that the TO as part of R1 developed a list of Elements, however R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest R2 be reworded to say “Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify…”. If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. In R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the requirement. We suggest R5.1 be reworded to say “A single record or multiple records that include at least one of the following:”. In R14, reword to indicate that the second bullet is only applicable if the first bullet is not completed within 90 days. We suggest this wording for the second bullet – “If recording ability is not restored within 90 days, report the inability...”
Group
Tennessee Valley Authority
Brandy Spraker
Yes
Yes
Yes
No
We respectfully request that a methodology similar to the one that was used in R1 is deployed in this requirement in order to determine an adequate percentage of flowgates needed for visibility of faults.
No
We believe that the time frames in the violation severity levels are too stringent when compared to the other items in the same violation level. A relatively short term delay in communication (30 to 60 days) is much less severe than not performing a function. Suggest lengthening out timeframes.
Yes
(1) We feel that the first bullet of 5.1 is not needed due to the content of the second bullet. If the team determines that it does need to be kept, a post-trigger record length of 30 cycles for the same trigger point would be adequate. (2) For R14, please provide additional clarity around the fact that if the equipment is returned to service within the 90 day time limit then it does not have to be reported. Respectfully suggest the second bullet to change to, “If not returned to service within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability.”
Individual
John Seelke
Public Service Enterprise Group
Yes
Yes
Yes

Yes
1. In R2, to avoid confusion as to what the phrase “BES Elements at the locations established in Requirement R1” means, we recommend that the Attachment 1, Step 1 have this sentence modified with a new parenthetical phrase an the end: “A single bus location includes any bus Elements at the same voltage level within the same physical location sharing a common ground grid (i.e., Elements directly connected to the bus).” In addition, since the only owners of those Elements may be other TOs or GOs, the reference to “shall notify the owners of those Elements” should be clarified. This requirement should be written as follows: “Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the TRANSNISSION OWNERS AND GENERATION OWNERS of those Elements, within 90 calendar days of determination, that the Elements require Sequence of Events Recording (SOER) and Fault Recording (FR).” 2. In R10, the last two bullets should be combined into one: • Under voltage trigger set at no lower than 85% of normal operating voltage for a duration of 5 seconds. 3. The language in R14 should have “either” added to clarify the required actions. In addition, the language in the second bullet “Report the inability to record data” was changed to “Report the inability to restore the recording ability.” See below. “Each Transmission Owner and Generation Owner, within 90 calendar days of the discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recoding (DDR) at the bus locations per Requirement R2 and Elements as per Requirement R7, shall EITHER: • Restore the recording ability • Report the inability to restore the recording ability to the Regional Entity along with a Corrective Action plan (CAP) to restore the recording ability.
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
(1) In Requirement R5.1, are the two bulleted items both required, or is only one item required, i.e., are the bulleted items listed with a coordinating conjunction of “and” or “or”? From past balloting on other Standards, e.g., CIP Standards, a numbered list in the Measure/Requirement mean the evidence example includes all of the items in the list. In contrast, a bulleted list provides multiple options of acceptable evidence.” Seminole requests clarification on this concern. (2) In Requirement R14, Seminole reasons that the requirement is intended to require the filing of a CAP if the inability to record data exists for longer than 90 consecutive calendar days. This reasoning is in line with the Rationale box for Requirement R14, however, the actual Requirement appears to require the filing of a CAP notwithstanding if the failure is remedied within 90 calendar days of discovery of the failure. Seminole requests that the requirement be revised to state that the filing of a CAP is only required if the inability to record exists for more than 90 calendar days from the date of discovery. (3) In Requirement R14, are the two bulleted items both required, or is only one item required, i.e., are the bulleted items listed with a coordinating conjunction of “and” or “or”? From past balloting on other Standards, e.g., CIP Standards, a numbered list in the Measure/Requirement mean the evidence example includes all of the items in the list. In contrast, a bulleted list provides multiple options of acceptable evidence.” Seminole requests clarification on this concern. (4) In Requirement R14, it appears that the intent of the SDT was to require the submission of a CAP if the failure was not remedied within 90 calendar days. If the failure is not remedied within 90 calendar days, it appears from the Requirements and the VRF/VSL penalty matrix that a CAP is required to be submitted to the RE within the same 90-day window. Seminole requests that the time to submit a

CAP be extended an additional 30 calendar days to read that an entity has 120 calendar days from the date of discovery of a failure in which to submit a CAP to its RE. This would allow a true 90-day window for fixing the CAP. For example, under the current language if an entity believes it will have remedied a piece of equipment on day 83, it would probably be best practice for that entity to prepare a CAP for submission in order to meet the 90-day CAP submission window in case delays arose. Seminole believes that this is not in line with the intent of the SDT and Seminole request the additional 30-day window for submission of a CAP, i.e., 120 days from date of discovery of the failure, and for Requirement R14 and the penalty matrix to reflect this change.
Individual
Brett Holland
Kansas City Power & Light
Yes
No
Attachment 1 and the median method results in an excessive number of buses requiring disturbance monitoring for a system (a large amount of tightly interconnected buses within a metropolitan area).
Yes
No
The inclusion of all permanent flowgates is our objection. This requirement will result in the inclusion of monitoring points that are not necessarily critical to the BES. The approach of the Western Interconnection to include all major transfer paths as defined by the Regional Entity seems to be a more logical approach.
Yes
No
We do not agree based on our earlier comments in regards to Attachment 1.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration L.P. agrees with the strategy the project team has taken to focus on the output of recorders – not the devices themselves. Recording technology is rapidly evolving and equipment-related requirements may be quickly be outdated otherwise.
Yes
Ingleside Cogeneration notes that the MVA thresholds applied are generally consistent with those established in EOP-004-2 “Event Reporting” and the criticality criteria used in CIP Version 5. This makes inherent sense, and would encourage the use of similar rules across all NERC standards in order to properly balance regulatory costs against benefits.
Yes
No
Unlike the MVA thresholds applied in R1, ICLP does not believe that the 1000 MVA threshold for generation facilities (R6.1.3.2) is consistent with other NERC criticality criteria. In addition, from the perspective of a Cogeneration facility, full nameplate capacity is normally not fully available to the Bulk Electric System. Therefore, either the threshold should be raised to 1500 MVA or should be revised to specify that the 1000 MVA threshold refers to “aggregate nameplate capacity available to the BES”.
Yes

Yes
Ingleside Cogeneration L.P. believes that the two to four year deployment schedule for recording capability is sufficient.
Individual
Venona Greaff
Occidental Chemical Corporation
Agree
Ingleside Cogeneration, LP
Group
Tacoma Power
Chang Choi
No
What is the purpose of the following clause in the definition of SOER: "…which may include protection and control devices"? Since the focus of this definition is on recording, and not equipment, consider removing this clause.
No
The 1500 MVA fault level includes many busses that are relatively unimportant to the BES. For example, in the 115 kV portion of our system, 83% of buses have fault levels above 1500 MVA. On our system, fault levels of 4000 MVA are a much better indication of buss important to the overall BES. However, rather than create a new MVA criteria in this standard, we suggest using criteria developed for other standards that determine important subsets of the BES. The requirements in CIP-002-5 R2.5 define substations that have a "medium" impact on the BES. Requiring a FR at a substations classified as "low" is overly burdensome. Alternatively, substations that do not have circuits subject to PRC-023-2 applicability section 4.2.1 should be except from FR requirements. Although we already have fault recorders on all 115 kV transmission substations with more than 3 lines, the purposed methodology would require additional Fault Recorders. These additional fault recorders would provide very little additional data, because the existing fault records include the remote ends of almost all transmission lines. The proposed standard does not take into adequate account the industry progress towards GPS synchronized microprocessor based relays. Much of the data required by FR is already recorded by relays. However, relay records only count as FR if they meet all the FR requirements for the entire substation. Rather than focus on obtaining 100% coverage of quantities at substations, this standard should facilitate taking advantage as much as possible of already installed hardware.
Yes
No
Considering the VSLs for Requirement R4, using "the product of the total number of monitored BES Elements and the number of specified electrical quanitities per each Element" would work well for current on the Element, but what about bus voltage shared by DDR on multiple Elements? Considering the VSLs for Requirements R4, R5, R8, R9, and R11, would it be more appropriate to base the percentages on how many required BES bus locations or BES Elements have the minimum recording properties, electrical quantities, or other specifications/parameters? (Consider the language in the VSLs for Requirement R10.) It seems like determining a percentage of the total recording properties, electrical quantities, or other specifications/parameters may be difficult in some cases. An example (scenario) of how these VSLs, as written, would be applied may be helpful. Should the Severe VSL for Requirement R11 be written something like the following? "The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets less than or equal to 10% of the total recording properties as specified in Requirement R11." In other words, is '1%' intentional? Considering the VSLs for Requirement R13, are the percentages based upon (1) BES bus locations, or BES Elements; (2) recording properties, or electrical quantities; (3) length of data recorded; or (4) a combination? An example (scenario) of how these

VSLs, as written, would be applied may be helpful. In the VRF/VSL Justification, the FERC VSL G3 comment for Requirement R11 is missing (page 34).
No
The disagreement is not so much with the implementation plan itself but whether part of the implementation plan should reside within the standard itself. More specifically, should part of the implementation plan be included under Requirements R3, R4, R5, R8, R9, R10, R11, R12, and R13? Of primary concern are BES bus locations or BES Elements that are added as part of the review at least once every five calendar years. An implementation plan normally addresses phasing in of the standard, or new version of the standard, not ongoing implementation.
There is general concern about the cost of implementation, especially cost sharing for installation of Dynamic Disturbance Recording (DDR). For example, the Responsible Entity seems to have latitude on selecting BES Elements, beyond the DDR locations identified in Requirement R6, Parts 6.1.3 through 6.1.7, and therefore which Transmission Owners and Generator Owners must install DDR to meet Requirement R6, Part 6.1.1. If two Transmission Owners share equipment at a BES bus location, which Transmission Owner is responsible under R1 and R2 for identification and notification? Under Requirement R5, Part 5.1, do the bulleted items constitute an ‘and’ or ‘or’ condition? For example, if a post-trigger record length of 50 cycles is available, but a fault lasts 51 cycles such that the final cycle of the fault is not captured, would this be compliant with the intent of Requirement R5, Part 5.1? If not, then it seems that either (1) both bulleted items would be required or (2) just the second bulleted item would be required. Consider changing “a single record or multiple records that include:” to “a single record or multiple records that include at least one of the following:” Under Requirement R5, Part 5.3, what latitude are Transmission Owners and Generator Owners afforded in establishing thresholds for neutral (residual) overcurrent and phase undervoltage trigger settings? Under Requirement R6, Part 6.1.7 attempts to define every area that uses UVLS as a “Major Voltage Sensitive Area.” UVLS programs are also used to address localized voltage issues. As currently written, a DDR would be required for every entity that uses any undervoltage relays, no matter how localized. We suggest removing section 6.1.7 as the other criteria in requirement 6 will provide widespread installation of DDRs. Under Requirement R8, Part 8.2, consider changing “…same voltage corresponding to…” to “…same voltage level corresponding to…” Under Requirement R9, Part 9.4, consider changing “…of at least one of…” to “…of any of…” Under Measurement M12, consider explicitly adding “station drawings,” or similar verbiage, as evidence. Device specifications and configuration or actual data recordings may be insufficient to demonstrate time synchronization; it may be necessary to demonstrate that cabling is connected. If failure of DDR is discovered, recorded data may not be retrievable for the period of 10 calendar days preceding a request. If a disturbance occurs before recording ability is restored, but an entity is compliant with Requirement R14, is it the intent of the standard that an entity could be found non-compliant with Requirement R13 for the failed DDR? Under Measurement M13, change “…evidence (electronic or hardcopy) data…” to “…evidence (electronic or hardcopy) that data…” Under Requirement R14, does loss of time synchronization qualify as a “failure”? Generally, it seems that this type of issue would be corrected quickly (within 90 calendar days of discovery) and therefore not require reporting. Under Requirement R14, if a Transmission Owner or Generator Owner restores the recording ability within 90 calendar days of the discovery of a failure, does the failure need to be reported to the Regional Entity to be compliant with Requirement R14? In other words, do the bulleted items under Requirement R14 constitute an ‘and’ or ‘or’ condition? In Attachment 1, Step 1, would bus Elements on the high-side of transformation at the same physical location be considered a single bus location and be distinct from the bus Elements on the low-side of the transformation, even if both sets of bus Elements share a common ground grid? In other words, is it possible to have two bus locations at the same physical location, even if they share a common ground grid, provided that there is transformation connecting the two bus locations? Consider a 230kV to 115kV substation. In Attachment 1, Step 1, what is meant by the verbiage “…or from other DME devices”? Additionally, the acronym ‘DME’ does not appear to be defined in the standard itself (only in the Rationale for R14).
Individual
Luminant Energy Company LLC
Luminant Energy Company LLC
Agree

Luminant Generation Company LLC
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
No
The methodology is acceptable, but a requirement should be added before R1 and the present R1 should be modified as noted below. a. Generator Owners should also be obligated to identify applicable bus locations where they own Elements using the Attachment 1 Steps, rather than delegating this obligation to the Transmission Owners. b. Generator Owners will be able to determine maximum available calculated three phase short circuit MVA after PRC-027-1 becomes a mandatory standard because this standard will require Transmission Owners to provide short circuit study information which makes this possible. In the implementation plan for this standard, Generator Owners could be exempt from compliance with R1 until after the applicable regulatory approvals of PRC-027-1. c. In addition, the scope of the bus locations that need to be considered for identification should be explicitly limited to locations where an entity owns Elements. d. Consider wording for the present R1, but new Requirement R2 like, “Each Generator Owner and Transmission Owner shall identify BES bus locations where it owns Elements for Sequence of Events . . .”
Yes
Yes
The criteria for selecting Elements requiring DDR in Requirement R6 are mostly acceptable. However, ATC recommends the consideration of the following wording changes: a. For R6 – Simplify the beginning with wording like, “Each Planning Coordinator or Reliability Coordinator (as applicable) shall . . .” b. For R6.1 – Specify more clearly that R6.1 is limited to BES Elements with wording like, “The BES Elements shall include the following:” c. For R6.1.1 – Make each sub requirement consistent with the parent R6.1 subject of “Elements” with wording like, “Elements at a minimum of one DDR location per . . .” d. For R6.1.2 – Make each sub requirement consistent with the parent R6.1 subject of “Elements” with wording like, “Elements at a minimum of one DDR location in . . .” e. For R6.1.3 – Add more clarity regarding the applicable Elements with wording like, “Elements at DDR locations, which interconnect the following generation resources to BES transmission buses:” f. For R6.1.4 – Make each sub item consistent with the parent R6.1 subject of “Elements” with wording like, “Elements necessary to monitor the following items:” g. For R6.1.4, bullet item 1 – Limit the scope of this item to only major permanent flowgates (similar to the other three bullets), rather than all permanent flowgates (which generally includes all BES circuits), and allow the Planning Coordinators to define what “major” means with wording like, “Eastern Interconnection – all major permanent Flowgates as defined by the applicable Planning Coordinator.”
Yes
ATC recommends the following: a. Regarding Requirement R2 – Similar to the recommendation for R1, Generator Owners, not just Transmission Owners, should be obligated to identify Elements at BES bus locations established in R1 that require SOER and FR. If any identified Elements are owned by other Generator Owners or Transmission Owners, then the Generator Owner or Transmission Owner should notify the respective owners. ATC recommends revising the R2 wording to, “Each Generator Owner and Transmission Owner shall identify which BES Elements require SOER and FR at the BES bus locations established in Requirement R1.” Revise the R2.1 wording to, “Each Generator Owner and Transmission Owner shall determine whether any required Elements are owned by other Generator Owners or Transmission Owners.” And finally, revise the R2.2 wording to, “If any required Elements are owned by other Generator Owners or Transmission Owners, then the Generator Owner or Transmission Owner should notify the respective owners of those Elements.” b. Regarding Requirement R3 – This requirement should follow through with the obligations that were prepared for in R2 by requiring SOER and FR for all of the Elements identified in R2, not just selected circuit

breakers. ATC recommends revising the R3 wording to, “Each Generator Owner and Transmission Owner shall have SOER and FR for each Element that they own and was identified per Requirement R2.”
Group
Nebraska Public Power District (NPPD)
Cole Brodine
Yes
No
For step 1 in Attachment 1 please confirm the following: For a 115kV and a 345kV bus in the same substation on the same ground grid is this considered two bus locations such that these would be used in step 3 as two of the 11 buses to calculate the median? For step 7 in Attachment 1 if I have a 230kV bus and a 345kV bus in the same substation in my top 10% is this acceptable to count them as two buses that require FR/SOER since it is a single location? Is this indicating that both buses need to meet the FR/SOER requirements? Please clarify for Attachment 1: Should a 115kV tap substation with no breakers but only a load serving transformer with a high side breaker be included in the fault bus list? It appears they should but would a tap sub with no breakers be required to have FR or SOER? Should generator GSU 13.8kV buses and tie transformer tertiary 13.8kV buses be in the bus fault list? Example list 1 appeared to have some 13.2kV buses but the instructions do say to use 100kV and above. Please confirm only 100kV or above buses should be used.
Yes
No
For clarification, “A minimum of one DDR location per 3,000 MW of the Responsible Entity's historical peak system Demand, inclusive of Requirement R6, Part 6.1, Sub-parts 6.1.2 – 6.1.7” means that for a peak demand of 3030MW a Responsible Entity must have at least two DDRs on its system and this requirement is satisfied if two DDRs are already on the system due to the other sub parts in R6? Has or should it be confirmed the RC or PCs have a clear understanding and listing of “permanent Flowgates” and locations necessary to monitor all Elements associated with IROLs? They may need to confirm they are using similar or same terminology.
No
“directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation…” I recommend these be moved to Moderate levels if not lower to match the criteria.
No
It is recommended to have 5 years to become compliant instead of 4 years to match this with the reassessment activities. Since there is no method to track the various percent compliant for the 2nd and 3rd years it is recommended to require 100% compliance by the final year.
For clarification on R2 after receiving notification from a TO that FR or SOER may be required how long does the receiving entity have to install the appropriate recording device? Please clarify if it is still 4 years to be 100% compliant? R3 can we clarify the circuit breakers that are not connected to lines and transformers designated in R4 are not required to be part of the SOER? For example, do not require SOER for a 115kV circuit breaker on a 115/34.5kV load serving transformer. R4 M4 states that “Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.” For individual relays used as recorders this may encompass a significant amount of data. Consider allowing evidence to be a single design standard or common general design example to be allowed as evidence rather than requiring all the detail data from every location which could be hundreds of relays with settings/drawings/records for example. There is a similar concern for R3 M3 evidence. R5 5.1 states: A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. Consider using 30 cycles instead of 50 cycles for post records since faults typically should be clearing faster (less than 10 cycles on most critical high voltage lines). This may reduce the risk of memory record overwrite

in relays that are of older vintage. DDR capabilities will also most likely be installed in the most critical areas for longer recording needs. R5 5.3.2 lists a required trigger setting for phase under voltage. Many relays used for FR will use the phase impedance zone reaches to trigger records. This can clearly define the reach for data to be triggered where defining an under voltage may be more difficult to control the reach. There is some concern with overwriting data in the relays with settings that are less intuitive for controlling how often a device may trigger. I strongly recommend allowing phase under voltage or phase distance reaches for 5.3.2 as trigger points. Generally the trigger requirements appear logical. There is some concern that these recording devices are not perfect and devices that appear to be functioning correctly will occasionally not trigger as set. These are not perfect devices. Is there a risk for non-compliance for devices that are set to meet compliance yet do not trigger correctly? This seems like an unnecessary risk. R8 8.1 seems to be a bit confusing. R8 8.1 allows a single phase to neutral voltage yet 8.3 appears to require all voltages. R8 8.2 is also similar in nature. Can this be changed to require one voltage and one current on the same phase? R11 states “11.2. Output recording rate of electrical quantities of at least 30 times per second.” Please clarify to make sure this can be clearly understood by an audit or enforcement team as well as owners. Is this processing speed or DSP of a device? For example some relays state “AC voltage and current inputs 8000 samples per second, 3 dB low-pass analog filter cut-off frequency of 3000 Hz” or “protection and control processing 8 times per power system cycle”. Are these examples what is asked for with 11.2? Most devices are likely to meet this rate. Does it really need to be in the standard? This seems excessive. Any options to reduce the requirements in this standard would help to limit the complexity and data to manage. R13 states: “13.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request.” This is a good goal to shoot far however data can be overwritten in relaying devices with the best intentions when numerous operations and voltage levels are used to trigger events. I don’t feel that the ability to guarantee data is available for this time period is fully under the control of the person setting the pickup and triggering in the device 100% of the time. This should not be a finable enforceable requirement and should be removed. On occasion failing equipment can provide such great amounts of data as to overwrite memories in relaying equipment. R13.4 states “Fault Recording and Dynamic Disturbance Recording data will be provided in electronic C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files.” Can the statement be added that if the device is not capable of providing COMTRADE files directly then it is acceptable to provide the data in its native format? I am concerned with the need to reformat data could risk loss of data before it may ever get to an analysis team. Some formats may not be easily convertible in older devices. Consider adding: Data content requirements and guidelines shall be in accordance with R13.3, R13.4 and R13.5 or other formats deemed acceptable by the requesting regional entity. R14 requires the tracking of recording failures and restoration. I recommend this only be required for recording devices not under another maintenance plan. For protective relays performing recording functions they should not be under this requirement if they are covered under PRC-005 which is a stringent maintenance plan that will be in place. This will reduce additional tracking requirements and burden.
Group
JEA
Tom McElhinney
No
The 1500 MVA selection criteria is too low. It needs to be substantially increased.
Yes
It is unclear if both of the two statements in R5.5.1 are required, or if meeting only one of the two is sufficient.
Group
PPL NERC Registered Affiliates

Brent Ingebrigtson
Yes
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, PPL; Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. The TOs have the system specific knowledge as to where on their networks, SOERs, FRs and DDRs should be installed to effectively capture disturbance data. Many TOs have existing DME equipment in place (previously specified per the Regional Entities) which provides the relevant system disturbance data required for disturbance analysis. The R1, R6 requirements may lead to installation of redundant equipment. Perhaps the R1, R6 requirements should specify that the TOs evaluate where SOERs and FRs are to be installed to effectively capture disturbance data? Re-specifying DME installation per PRC-002-2 may result in redundant evaluation and equipment installation of DMEs. Previous electric sector DME efforts driven by PRC-002-1 and Regional Criteria should be recognized in the specifications for DME installations.
No
PPL made the comment in the 11/19/13 webinar that DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data, GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording and storage infrastructure, and experts in monitoring and maintaining such equipment; stand alone GOs do not. The webinar presenters stated that making R9 pertain to TOs rather than GOs would make TOs responsible for monitoring GO equipment, and there is no technical reason for making them do so. PPL disagrees in that disturbances do not originate exclusively in generation plants, and the majority of such events may in fact stem from transmission system problems (as was the case for the Northeast blackout of ’03). That is, one can just as easily say that R9 makes GOs responsible for monitoring reactions to the TO’s system, and there is no technical reason for making GOs do so. Given this inability to establish a universal cause-vs.-effect rule for disturbances the least-total-cost approach should be followed, and centralizing DME makes more sense than splitting it between involved entities (TOs) and those who merely hand-over recordings (GOs). This point was made again in the 12/5/13 NAGF outreach webex meeting, and there did not appear to be a strong rationale for having GOs be designated Responsible Entities when they in fact would be mere appendages, i.e. installing what are to them black boxes and handing-over recordings that they don’t understand.
Yes
Yes
No
Since there has been previous DME installation guidance provided by Regional efforts (via a Regional Standards or Criteria), it should be assumed that TOs have previously installed DME (SOER, FR, DDRs) equipment in locations specified per the Regional or local requirements. Therefore, requiring TOs to have any new DMEs installed per R1, R6 within 6-9 months of when PRC-002-2 becomes enforceable is not justifiable. There should be a (12-24 month) grace period to install any newly required DMEs (SOERs, FRS, DDRs) per PRC-002-2 R1 and R6. Concur with implementation time frames of R2, R7 and R14 requirements.
1. It appeared from the 11/19/13 webinar that the R9 obligation for GOs to “have” DDR does not mean that they must own such equipment, and this position was confirmed in the 12/5/13 NAGF outreach meeting. That is, it would do just as well to have an agreement with the TO to fulfill the PRC-002 requirements if and where the TO already has DDR on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002. R9 should have a footnote saying that “This standard defines the ‘what’ of DDR, not the ‘how.’ GOs may install this equipment or, where the TO already has suitable DDR, contract with the TO.” It would be still better

to just eliminate GOs from the requirement, however, per our comment to question #3 above. 2. R6 sets DDR applicability criteria based on the “nameplate rating,” but doesn’t say of what. This could be the generator, or the most-limiting component. We believe that applicability should be based on the most-limiting component, since this sets the actual output achievable. The term, “Facility Rating,” as defined in FAC-008 should then be used to avoid confusion. 3. The frequency and Hz/s settings of R10 should have a latch-time criterion, to prevent inadvertent triggering of the DME. We suggest three cycles. 4. R10 calls for DME to be triggered at no lower than 85% of normal voltage with a latch-time of 5 seconds, but the 5-second ride-through requirement of PRC-024 is only +/-10%, which is also often where V/Hz relays are set. A trigger of 85% voltage x 5 sec may therefore cause DME to miss the action. 5. Triggered (as opposed to continuously-recording) DME needs to have sufficient storage capability to capture a major disturbance and a potentially large number of aftershocks, but we have no way of knowing how many such recordable events may occur, creating a compliance risk. The SDT should establish the expected maximum number of recordable events and state it in the standard.
Group
New York Power Authority
Saul Rojas
No
The definition for SOER optionally includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit breaker position. The purpose of the standard is to “have adequate data available to facilitate analysis of BES disturbances”. We don’t see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis.
No
The methodology in Attachment 1 is overly complicated (9 steps); and following eight of these required steps, it is then left up to the T.O. to add “discretionary” stations, if desired. Just using the highest 11 station fault MVA values may not be the most accurate. Contributions from a foreign, nearby utility can raise a station’s fault values, even though the station itself is not that critical to the listing entity. Using “Station” instead of “Bus” or “Location” would be more definitive. e.g. a 230 kV “Station”, a 345 kV “Station”,…). The term “bus” can be defined in different ways, so can “location.”
Yes
No
R6.1.6 – This requirement could lead to unnecessary installation of DDRs in non-integral substations.
Yes
Yes
R10 It is stated that triggered records from existing equipment can be accepted in lieu of continuous recording if the triggered records meet the criteria in 10.1 and 10.2. If continuous recording is available and meet all criteria, are triggered DDR records required? R13.3 There is no need to require this data to be written in CSV format. Tab delimited text would work as well and would not limit the use of commas in descriptors or other entries. The format described in Attachment 2 is limiting and incomplete (see comments on Attachment 2).. R13.4 This requires that Fault Recording and Disturbance Recording data will be provided in COMTRADE (C37.111) formatted files, but does not specify a revision level or year for the COMTRADE standard. The requirement should specify “C37.111-2013 or later” in order to require a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data. Attachment 2 The format in Attachment 2 is limited and incomplete. While the information required is obviously necessary, the format limits or omits information available from some SOERs.

R13.3 states that the files must be comma-delimited, but Attachment 2 makes no statement about the length of any string or value. There is no provision for SOERs which may have detailed descriptors of the contacts being monitored but may be a single string. “Local Time Offset from UTC” should be expressed in hours before or after UTC rather than letter designations. There is no provision for acceptable terms for “State” except for “OPEN “and “CLOSE”. Other terms may be more appropriate for some devices monitored by an SOER, such as “ENABLED” or “DISABLED”, “ON” or “OFF”, etc. In short, Attachment 2 appears to be an attempt at defining a standard but does not adequately define a format. Development of such a standard may be better left to an IEEE Working Group or other entity.
Group
IRC Standards Reveiw Committee
Charles Yeung
Yes
No
We agree with R1, but we do not see the need for R2 since through R1 and Attachment 1, each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR). There is not another owner(s) that a TO needs to communicate the list to, unless the “list of BES bus locations that it owns” depicted in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that is the case, then Step 1 in Attachment 1 needs to be clarified to distinguish the need for R1 and R2.
No
This is a “fill in the blank” as identified in the FERC Order 693 and was written to be complied with by the RROs for years. We question why there is need for the RC and PC to comply with these. In fact, the Paragraph 81 activities have identified many requirements that are by the FERC’s perspective not consequential or primary for reliability. We do not believe that a mere reassignment from the old RRO entities to the RC or PC that these requirements suddenly become critical to reliability. NERC should consider other avenues to provide entities with methods to acquire fault data for event analysis. The solution to everything we do shouldn’t be a standard. In fact nearly all new relays and digital meters have disturbance recording capabilities, it is possible to acquire data for event analysis without DDR. Since the intent of this standard is primarily to have post-event data available, it can be argued this is not a critical reliability standard. We point out that the NERC Rules of Procedure have a detailed section on disturbance response procedures.
No
R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but Part 6.1.1 and 6.1.2 are not criteria for “Elements”, but rather, they are criteria based on demand size and footprint. It would clarify for compliance if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., Pats 6.1.1 and 6.1.2), and one for the location/element (Parts 6.1.3 to 6.1.6).Also, M6 for R6 states that the responsible entity must “accurately” identify elements requiring DDR per numerous sub-requirements under R.6.1. and measures degrees of compliance against an identified set of points as specified per 6.1.4. R.6.2. requires that entities, at a minimum, perform a new assessment for DDR locations every 5 years. When there are elements added to the Interconnections or long-term system reconfigurations that take a DDR(s) out of service or renders them incapable of recording the required data, should that be a trigger for a reassessment?
No
Yes
Individual
David Jendras
Ameren

No
(1) Ameren also supports the SERC Protection & Control Subcommittee (PCS) comments and hereby includes them by reference rather than repeating them all.
Yes
No
(1) We ask the SDT to replace 'Planning Coordinator' with 'Regional Entity' in 4.1.1 because the Regional Entity has a wider view, and it promotes consistency.
No
(1) In conjunction with our Planning Coordinator we have voluntarily installed over 30 PMUs which was a significant effort and resource commitment over the last 3 years. Even though they have not yet been needed for disturbance analysis, some operating visualization tools are being used and we have reviewed some minor perturbations. However, if we would still need to have a PMU covering every generator with 500 MW or greater as in 6.1.3.1, as well as all permanent flowgates, as covered in 6.1.4, that would require us to add many more PMUs to the system. We believe this would be burdensome, given the effort already undertaken over the last 3 years to get to where we presently are. We respectfully disagree with the drafting team's brief justification in the Rationale for R6.
Yes
No
We request the SDT to make the following changes: (1) Add 1 month to item 3 for the TO to identify BES Elements in R1. (2) Delete 'bus locations and' in item 6 so that the total percentage (%) is based on BES Elements throughout the Implementation Plan. There are bus locations at which there are several different owners of the BES Elements. (3) Replace '24 months or more' with 'up to 60 months' in item 9. (4) The Implementation Plan Summary is very helpful but the Entity is incorrect for R8, R9, and R10.
We request the SDT to make the following changes: (1) In R1, add 'After identifying BES bus locations, each TO shall identify the BES Elements directly connected to that bus location at its voltage level.' We request allocating another month to do so. We believe that this will provide a consistent reference for R2 which refers to BES Elements as if they've been established in R1. (2) In R3, insert 'Transmission Owner' before 'bus locations' to make it consistent with the page 32 Guideline for R3 explanation that the GO does not need SOER at its GO bus locations. Also insert 'BES' between 'each' and 'circuit breaker' because not all breakers are BES Elements. It then states 'Each Transmission Owner and Generator Owner shall have Sequence of Events Recording (SOER) for circuit breaker position (open/close) for each BES circuit breaker they own connected to the Transmission Owner bus locations as per Requirement R2.' (3) Include the BES bus location along with the BES Element in R6 so that it is clear that DDR is only required at one terminal of a two-terminal Element. (4) Reword R8 and R9 to 'Each Transmission (Generation) Owner shall have Dynamic Disturbance Recording (DDR), for each location and Element as dictated by the Responsible Entity per Requirement R7, to determine…' (5) Reword R11 to be similar using 'that is responsible for' to R10 to 'Each Transmission Owner and Generator Owner that is responsible for Dynamic Disturbance Recording (DDR) as per Requirement R7 shall conform …' (6) Reword R12 to 'Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 shall time synchronize data to within …' (7) If at all possible we would like another opportunity to provide comments on CEAP for PRC-002-2 in the next draft. Several aspects of this draft made in unclear as to what is required, and therefore difficult to assess cost impact.
Individual
Chris Scanlon
Exelon Companies
Yes

Yes
We agree but, consider the following comments. The R1 method is designed to assure a minimum level of SOER and FR is available to analyze events. It does so by requiring a certain process must be periodically performed by the entity. This seems to be a good process to ensure that an entity has a minimally acceptable level of monitoring on their system. However, the drafting team should consider a less burdensome alternative for entities that are working to install modern equipment with FR and SOER capabilities on all their circuits. Once a system includes a high percentage of modern equipment with SOER and FR capability (also see comments to item 7), R1 through R5 are not needed and become purely burdensome compliance items. At our company gathering data to ensure 100% compliance is a high burden activity. An alternative method for entities with high percentages of modern equipment installed might be to provide a list of BES transmission line terminals showing that at least 50% (or another appropriate percentage) of all employ modern equipment with SOER and FR capability (also see comments to item 7). This data is typically available (we keep it on an ongoing basis) with a very minimal effort. Only a very minimal effort should be required for a system that is already highly monitored and doesn't need a standard to force the issue. This method would be an alternative to R1 through R4 (R5 becomes moot when a high percentage of transformers are monitored) which are designed for entities not monitoring their system. The entity would choose which method to use and the effort required on a highly monitored system would be minimized.
Yes
No
We believe the drafting team has done a good job of trying to focus on the important BES elements that should require Dynamic Disturbance Recording. Requiring DDR for the most important BES elements rather than all BES elements at a certain station is technically sound and a major improvement over some attempts at past criteria to determine which elements should require DDR. We concerend however that about the specificty for determination as to the number and location of where DDR will be required per this requirement. The requirment may result in an unnecessary number of installations. We urge the drafting team to provide for the PC to determine the number and location of the devices. Addtionally, use of the NERC book of flowgates may not support again the necessary data required because every line in a Flowgate or IROL, IROLs is not always dynamic limited.
No
We don't agree that R3 is necessary at all, see item 7 comments. In a large company hundreds of pieces of equipment require monitoring. If one item out of hundreds are missing, the effect on monitoring is minimal. The drafting team should consider changing the lower violation severity level to more than X% but less than 95% (instead of 100%). Zero tolerance approaches, especially on standards that "look back" and support analysis are unnecessary and wasteful of engineering resources.
Yes
Comments on R3: R3 states that circuit breaker position must be monitored for identified breakers. In our companies standard design, we connect circuit breaker auxiliary contacts to relays that include monitoring. However, this requirement will present a significant burden since a database must be created to cross-reference prints to prove that hundreds of breaker auxiliary contacts are connected to satisfy compliance requirements. Since three phase currents are to be monitored under the proposed Requirement3, this information can be used to determine circuit breaker status in lieu of monitoring a 52 contact. With three phase current values available, it is not difficult to figure out when breakers were opened based on loss of current and is actually more accurate than breaker auxiliary contacts. It is very straight forward to figure out when breakers are opened based on loss of current for a straight bus configuration. If a single circuit breaker in a ring bus or similar configuration opens for some reason and flow is not interrupted the sequence of breaker openings can still be determined using currents. It is also not necessary to know exactly when a breaker in a ring bus opens if flows in the ring are merely rerouted. Thus, a detailed sequence of events timeline of a power system disturbance can be determined without the use of a circuit breaker contact. In rare cases connection of a circuit breaker contact may have been mistakenly excluded from the

protection design. In this case, complying with the standard as written could require installing 1000 feet or more of control cable in an EHV switchyard, incurring a high cost for very little gain. Thus, we believe the drafting team should eliminate this requirement as it just creates a significant burden, potentially adds cost, provides no commensurate increase in reliability, and is not necessary for events analysis when three phase currents are already required. Comments on R4: It is a natural progression for a TO to upgrade BES lines before upgrading BES transformers since BES lines are subject to many more faults and operations. Thus, modernizing BES lines first has the greatest impact on reliability. For example, a large % of our comapies T-lines employ modern relays with FR and SOER capability and the remaining lines will have this capability shortly. These upgrades are being done on previously determined schedules and include all 138 kV and above lines. The percentage of BES Transformers with modern equipment is much less (15-20%) and upgrades are typically only done when transformers infrequently fail or when protective equipment is obsolete and problematic. Although R4 does state that the TO/GO shall have fault recording necessary to determine required quantities (transformer information can be determined from monitored line data as needed), the drafting team should consider revising the guidance section of R4 to state that it is adequate to monitor lines and use their fault recordings to determine transformer quantities. The drafting team should also consider just eliminating R4.2.1. Monitoring lines is much more important and provides information to determine flows in transformers. This would also recognize that the natural progression of system upgrades is to concentrate on the most exposed and problematic areas (T-lines). The number of transformers with increased monitoring is increasing sufficiently already and monitoring of transformers inherently benefits from the rapidly increasing level of monitoring on transmission lines. Comments on R5: R5.3 states that trigger settings need to include Neutral (residual) overcurrent and phase undervoltage. RFC had a disturbance monitoring standard for a few years that we worked diligently to comply with. It required triggering on one or more of various quantities including negative sequence current, negative sequence voltage, residual current, undervoltage, overvoltage, or overcurrent. ComEd met this requirement in hundreds of devices by triggering on residual current (for grd faults), phase overcurrent (for multi-phase faults), and pickup of any forward or backward (if used) phase distance zone (for multi-phase faults). Undervoltage elements weren’t always available. The drafting team should consider modifying this requirement to allow phase undervoltage or phase overcurrent as a trigger for multi-phase faults. Having to tweak hundreds of relay settings (an arduous and expensive process) to meet a NERC standard that is slightly different than the RFC standard just doesn’t seem right. There is a good argument that once a system is highly monitored, triggering an event record when the relay trips provides sufficient information for events analysis. We do not believe that a standard specifying what to trigger on is necessary at all for a highly monitored system. Having to go back and change event trigger equations on a highly monitored system is purely burden to the registered entity with no commensurate increase in reliability or increased capability to analyze disturbances.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
No
Please see the comments of the NAGF SRT. I support their response to this question.
No
Generator should not be a functional entity for this standard. In cases where generators own a breaker on a transmission system, the only requirement should be a breaker status signal, which properly should be supplied under the interconnection agreement.
No
The standard is too prescriptive for DDR. The TO should select the sites, install and maintain the DDR they properly need to analyze a disturbance on their system. The standard should simply require "DDR shall be installed as necessary to analyze a fault on the TO's system". Violations of the standard would only occur if a fault is unable to be analyzed due to equipment not being installed (not due to failure or outage of installed equipment).

No
No
See the NAGF SRT comments. Smaller entities who may have one SOE system to install will be forced to comply 100% within two years.
See NAGF SRT comments.
Group
Corporate Compliance/Engineering
Ed Croft
Yes
No
The document “Mapping of Standard’s Introduction of BOT Approved PRC-002-1 to Proposed PRC-002-2” from January 2013 described line terminals above 200 kV and large generators/transmission stations which warrant this level of data gathering, as they represent the backbone of the transmission system. It would be better to start with this system level first and test out data collection. For the sake of comparison, the approximate median value of the 11 highest (short circuit) MVA PSE buses where digital fault recorders are already in place, is 6800 MVA. Lowering to a short circuit MVA level of 1500-2500 MVA quadruples the quantity of collection sites.
Yes
Yes
No
Referring to comments for Question 2 on this Comment Form, it would be prudent to at first require a subset of the Fault Recording, SOER and DDR to be up and running and monitored for a time. Then NERC, WECC and entities can refine the standard based upon what we learn. In a nutshell, we should start small.
No
Referring to comments to Question 2, it would be prudent to at first require a subset of the Fault Recording, SOER and DDR to be up and running and monitored for 2-3 years. Then NERC, WECC and entities can refine the standard based upon what we learn. In a nutshell, we should start small.
Group
Florida Municipal Power Agency
Frank Gaffney
No
Please see response to question 7.
No
Please see response to question 7.
No
Please see response to question 7.
No
Please see response to question 7.
No
Please see response to question 7.
No
Please see response to question 7.

FMPA does not believe that a standard is justified for Disturbance Monitoring, as such, we believe that disturbance monitoring is better addressed through guidelines than through a standard, as further discussed below. In the scheme of things, disturbance monitoring provides very little value to operating the bulk-power system reliably as compared to other standards. Establishing SOLs and operating to them; coordinating and maintaining effective protection systems; maintaining supply/demand balance and frequency; cyber security; and effective and trained human resources are greater than one quantum step more important to reliable operations than equipment installed simply to ease the ability to perform post-mortem analyses on events and to validate stability modeling that cannot be that accurate in the first place simply due to Chaos Theory (e.g., the Butterfly Effect) and the inability to predict the future accurately. While installing DMEs may be good / prudent action, FMPA believes it is imperative to avoid a mode of thought that seems to prevail among many within our industry, and that is a mode of thought that if something is good for reliability, then we need to write a standard for it. Such mode of thought is counterproductive and stunts creative improvement because it creates a perverse incentive to only do the minimum to meet the existing standards due to the danger of better performance causing an increased level of governmental regulation. Governmental regulation should be to minimum requirements while not stunting the creativity of the industry to perform better than required, and FPA Section 215 is crafted with that thought in mind: "The term `bulk-power system' means-- `(A) facilities and control systems NECESSARY FOR OPERATING an interconnected electric energy transmission network ..." (emphasis added) "The term `reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system." While DMEs may be good/prudent, they are not necessary to provide reliable operation of the bulk-power system. In addition to a lack of technical justification, a standard that requires DMEs is also not justified from a cost/benefit perspective. The benefit of DMEs as stated in the purpose of the draft standard are to assist in post-mortem analyses of events. We have been doing event analyses for decades without the standard. Yes, they may take longer to perform do to the difficulty in establishing a sequence of events post-mortem and other challenges, but, we were able to do it. So, the benefit of a DME is to shorten the time and effort it takes to do a post-mortem (what is that, maybe three or four person-years, maybe a million?) compared to a cost of installing these devices and maintaining them on hundreds of buses (maybe $10's of millions) for events that may happen once in 10-20 years close enough to a DME to matter. In addition, the system has changed a lot over the last 10 years since the Northeast Blackout of 2003 and we can gain much more information now from microprocessor based relays prevalent throughout the system and phaser measurement units (PMUs) also installed throughout the system. Additionally, the effort does not justify the compliance administration costs at both the entities and at NERC and the Regions for administering compliance to this proposed standard. The standard as written is complicated, long, has many requirements, and in general is far too complicated and onerous in relation to its minimal reliability benefit. Also, how would such a proposed standard impact compliance with PRC-006, EOP-004 and other standards that require post-mortem event analyses? In conclusion, FMPA believes that a standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.
Individual
Oliver Burke
Entergy Services, Inc.
No
1) Add “balanced three phase” between “dynamic” and “power” in order to clarify the context of Dynamic Disturbance Recording. The revised definition would be “The recording of time sequenced data for dynamic, balanced three phase power system characteristics such as power swings, frequency variations, and abnormal voltage problems.” 2) The definition of SOER presently uses the phrase “… status of Elements, which may include protection and control devices.” Recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also, the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status. 3) Recommend not using the acronyms SOER, FR, and DDR as defined NERC Glossary acronyms. These acronyms have historically been

used by industry to label the recording equipment; therefore the same acronym should not be used when referring to the equipment's data.
Yes
Yes
No
We believe the proposed DDR installation criteria will require an excessive number of installations, has not been technically justified by the SDT for the increase in DDR installations which will be required, and will be unnecessarily burdensome to the industry. Industry experience shows that disturbance events for which DDR information and analysis is needed are very rare, and we believe the R61.1 criteria puts us closer to what should be a target number of installations rather than a minimum number.
Yes
No
Clearly state the timeframe required for implementation of newly identified locations resulting from the R1 five year assessment.
1) All SER and FR data requirements should be included as part of a single table and referenced in a single requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation multiple requirements. 2) Similar to 1) above, all DDR data requirements should be included as part of a single table and referenced in a single requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation of multiple requirements. 3) Add "by voltage level" in Requirement R1 so that it reads "Each Transmission Owner shall identify BES bus locations by voltage level for Sequence of Events Recording (SOER) and Fault Recording (FR)." This is consistent with Attachment 1, Step 1 and clarifies that the FR and SOER are only required at that voltage level. 4) In Requirement R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the Requirement. Suggest Requirement R5.1 be reworded to say "A single record or multiple records that include at least one of the following:" 5) Reword Requirement R14 to 'Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 upon the discovery of a failure shall: (a) Restore the recording ability within 120 calendar days; or (b) "If recording ability is not restored within 120 calendar days, demonstrate efforts to correct the unresolved failure." Recommend increasing the allowed repair time by 30 days to allow for non-inventoried repair parts and limited access of repair personnel to such equipment which may be restricted during certain periods of the year.
Individual
Tommy Drea
Dairyland Power Cooperative (DPC)
No
R4. If information is required to be gathered for every transmission line connected to the bus, equipment may need to be installed to capture this information. The capital cost may be significant to some smaller TO's to install the FR equipment capable to capture this information. The SDT is encouraged to consider this fact in regards to this requirement and in the implementation plan.
No
If information is required to be gathered for every transmission line connected to the bus, equipment may need to be installed to capture this information. The capital cost may be significant to some smaller TO's to install the FR equipment capable to capture this information. The SDT is encouraged to consider this fact in regards to this requirement and in the implementation plan.
No

Please provide the technical justification for Requirement R6.1.1.
No
It is unclear what the implementation timeframe is for newly identified facilities after the original implementation of the standard. Should a facility be identified in the future as requiring a SOER, FR or DDR it is unclear how long the responsibility entity has to install equipment to capture the necessary data to be compliant.
Group
Duke Energy
Michael Lowman
Duke Energy recommends the following suggestion to the new definitions (1) Dynamic Disturbance Recording (DDR) –The recording of time sequenced data for dynamic power system analysis comprising characteristics such as power flow, and frequency and voltage excursions. (2) Fault Recording (FR) –The recording of time sequenced waveform data, such as current(s) and voltage(s), for short circuits or failure of BES Elements. (3) Sequence of Events Recording (SOER) –The recording of time sequenced data for change in status of BES Elements, which may include components of protection and control systems.
Yes
Yes
Yes
Yes
Yes
(1) Duke Energy believes that ambiguity exists between Requirement 14 and the Rationale. The standard suggests that an entity must “Report the inability to record data to the Registered Entity along with a Corrective Action Plan (CAP) to restore the recording ability” within 90 calendar days. However, in the Rationale for Requirement 14, the language suggests that a Registered Entity must issue a report on the inability to record data to the Registered Entity after a timeframe of 90 days. (2) Triggering of frequency events in Requirement 10 should be adjusted. Significant events will be missed if recorders on generators are set to trigger below 59.75. Also, the rate of change wording is confusing and should trigger if the rate of change is greater than a value not less than a value. Lastly, the Rate of change frequency set point of 125 mHz is too large and should be triggered on generation around 20 mHz per second. (3) Electrical quantities identified in Requirement 9 should better align with MOD-26 (MW, MVARS, Terminal Volts, Field Volts, Field Amps). (4) According to the rationale for R6, the intent of the requirement is to “ensure that there are sufficient BES Elements identified for DDR because of the crucial role DDR plays in wide-area disturbance analysis. Additionally, DDR is used for capturing the Bulk Electric System transient and post-transient response and for validating the system model’s performance.” Duke Energy believes to require that DDRs be located in areas necessary to monitor all elements of permanent Flowgates is excessive. Permanent Flowgates fall into one of three categories: Voltage, Stability, or Thermal. The majority of the Flowgates identified are classified as being Thermal. Thermal Flowgates are chosen due to concerns with steady-state loading and not for transient/post-transient activity. With some PCs or RCs having as many as 1000 permanent Flowgates, the cost versus reliability gain would be astronomical. For Flowgates that have been identified to be voltage or stability related, the case can certainly be made to have DDRs monitor them in the transient/post-transient timeframe. We suggest that all permanent Flowgates should be removed from the requirement and only keep those permanent Flowgates that have been identified as voltage or stability limited. This would reduce the

amount of Flowgates requiring DDRs, reduce the cost for industry stakeholders, and still achieve the intent of this requirement.
Group
Southern Company
Wayne Johnson
Yes
Yes
Yes
No
a) In the Background section, the SDT explains the basis for the 500MW threshold; however, there is no explanation/ basis for the 300MW at locations over 1000MW. b) It is not clear in R9 whether the specification for signal measurements is on a generating unit basis or if the signals of interest are a per line basis aggregate at generating stations. Please more clearly specify if the signals of interest are individual unit measurements or plant total measurement (grouped by output circuit, plant total, etc.). This determination weighs heavily on the cost and method of implementation where new equipment must be installed. Example: (i.e. combined cycle plant (1075MW total) with units of 325, 325, 425 but only one transmission line)? c) In reference to the R6.1.4: The monitoring of all elements of a permanent flowgate should be changed to only the major elements or perhaps those that contribute more than 20%. In some cases multiple lines of 500, 230, and 115kV may be involved but the lower voltage lines may only contribute 5-10% of the total capacity. Having to install DDR capability at these multiple locations is overly burdensome and does not enhance the overall goal of this Standard.
Yes
No
Referencing Note 9 of the Background section, ‘Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant’; we feel the requirement to be ‘25% compliant within two (2) years following notification of the list’ is problematic and overly burdensome for both TOs and GOs. We feel that a more appropriate timeframe for implementation would be as follows: o At least 25% compliant within three (3) years following notification of the list o At least 50% compliant within four (4) years following notification of the list o 100% compliant within five (5) years following notification of the list
a) The requirements of R3, R4, R5 and R12 for SER and FR data should be included as part of a single attachment/ table and R3 should simply reference the table. As structured presently, if an owner fails to include provide data for a single required element, they would be in violation multiple Requirements. b) Similar to a) above, R8, R9, R10, R11, and R12 for DDR data should be included as part of a single attachment/ table or possibly separate attachments/tables for TOs and GOs and referenced in a single Requirement. As structured presently, if an owner fails to include provide data for a single required element, they would be in violation of multiple Requirements. c) The inclusion of the word ‘either’ in R4.1 seems redundant. d) R10 allows the use of triggered records from equipment installed prior to the effective date of PRC-002-2, but does not specify how many records an entity must be able to produce in the retrievable period specified in R13 as 10 days prior to a request. This specification is crucial to the amount of memory requirements of existing equipment. At the maximum trigger frequency (triggering every 3 minutes), the existing equipment becomes effectively a continuous recorder. For existing equipment with triggered recording capability, how many records are required to be available in the 10 day retrievable record?
Group
El Paso Electric
Pablo Onate

Yes
Yes
Yes
No
No. Requirement 6 contains too many potential DDR locations. SDT should provide clarity between requiring one DDR per system, requirement 6.1.2, versus requirements 6.1.5, 6.1.6 and 6.1.7. The criteria for placement need to be clarified.
Yes
1. In respect to requirement 6.1.4, will entities be required to monitor multiple lines of a major transfer path or only one? 2. In respect to requirement 6.1.5, will one entity owning an HVDC connecting two interconnections be required to monitor both sides of the HVDC element?
Individual
Catherine Wesley
PJM Interconnection
Yes
Yes
PJM does support the methodology and also is providing the following comments. The R1 method is designed to assure a minimum level of SOER and FR is available to analyze events. It does so by requiring a certain process must be periodically performed by the entity. This seems to be a good process to ensure that an entity has a minimally acceptable level of monitoring on their system. However, the drafting team should consider a less burdensome alternative for entities that are working to install modern equipment with FR and SOER capabilities on all their circuits. Once a system includes a high percentage of modern equipment with SOER and FR capability (also see comments to item 7), R1 through R5 are not needed and become purely burdensome compliance items. At our company gathering data to ensure 100% compliance is a high burden activity. An alternative method for entities with high percentages of modern equipment installed might be to provide a list of BES transmission line terminals showing that at least 50% (or another appropriate percentage) of all employ modern equipment with SOER and FR capability (also see comments to item 7). This data is typically available (we keep it on an ongoing basis) with a very minimal effort. Only a very minimal effort should be required for a system that is already highly monitored and doesn’t need a standard to force the issue. This method would be an alternative to R1 through R4 (R5 becomes moot when a high percentage of transformers are monitored) which are designed for entities not monitoring their system. The entity would choose which method to use and the effort required on a highly monitored system would be minimized.
Yes
No
PJM is concerned about the specificty for determination as to the number and location of where DDR will be required per this requirement. Our concerns include the number of DDRs may be sufficient for monitoring but not for data validation. Monitoring lines may not provide the data to adequately perform disturbance analysis. Additionally, the requirment may result in an unnecessary number of installations. We urge the drafting team to provide for the PC to determine the number and location of the devices. Addtionally, use of the NERC book of flowgates may not support again the necessary data required because every line in a Flowgate or IROL, IROLs is not always dynamic limited.
Yes

Individual
Joel Charlebois
AESI Acumen Engineered Solutions International Inc.
Yes
Yes
Yes
Yes
Yes
Yes
It is understood that the intent of this version 2 of the PRC-002 Standard is to ensure that sufficient recording capability exists without being prescriptive as to the type of equipment that must be installed to meet the recording capability requirements. It is also understood that the SDT did not wish to be unnecessarily prescriptive with respect to periodic maintenance activities, and as such, this version 2 of PRC-002 contains no such requirement. It does not appear however that the Standard would necessarily ensure that Entities continue to have the required recording capability over time following initial installation and commissioning and after completion of the Implementation Plan. Although an Entity should be compliant at all times, is it plausible that an Entity could be unaware if some of the required recording capability is deficient or no longer exists? Disturbances do not occur very frequently, and an Entity may not become aware of deficiencies for many months or years until a disturbance occurs, when the disturbance data is requested; at which point they realize that the disturbance recording functions or capability is deficient in some manner. It could be argued that verifying compliance, and ensuring that the required recording capability exists, is the task of the auditor; however, this is dependent upon the Standard being included in an audit, and an audit itself may only occur once every 3-6 years. We suggest that the SDT consider adding a requirement for Entities to simply perform a periodic verification of the required recording capability, without specifying how to verify such recording capability, on an interval to be determined by the SDT. There are many mechanisms available for verification such as downloading recorded data, performing equipment self-tests, etc. Allowing Entities to perform periodic verification of the required recording capability in a manner they choose is consistent with the spirit of the Standard of not being unnecessarily prescriptive, and is consistent with ensuring that the required recording capability is in place.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
Believe that applicability to TO and GO entities should be limited to those with the current equipment capable of the required monitoring and should not de facto create a situation where an entity has to purchase equipment to comply with the requirements of the standard, including the storage and auditing of post-fact information sufficent to meet the requirements.

Group
SERC Protection and Controls Subcommittee
David Greene
No
The SERC PCS requests that the SDT to make the following changes: 1. Add ‘balanced, three phase’ between ‘dynamic’ and ‘power’ in order to clarify the context of Dynamic Disturbance Recording. Thus it would read ‘The recording of time sequenced data for dynamic balanced, three phase power system characteristics such as power swings, frequency variations, and abnormal voltage problems.’ 2. Also the definition of SOER presently uses the phrase “… status of Elements, which may include protection and control devices.” We recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status. 3. We do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should be given to using the word “data” in place of the word “recording”, such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD.
Yes
Yes
No
1. Our industry experience is that disturbance events for which DDR information and analysis is needed are extremely rare (perhaps one per decade; in fact we’ve not yet experienced such an event). We believe that the proposed R6.1.4 alone would increase our number of NERC required DDR for one of our members at least thirty-fold. The SDT has not provided technical justification for this proposed significant increase. For this member, the other parts of 6.1 may well triple their NERC required DDRs. We ask the SDT to consider a reasonable approach and omit Requirement 6.1.4 and reconsider it in the five-year review of this standard if NERC-wide experience in the meantime warrants it. Perhaps this is a regional issue and some regions have a stronger need; if so, we suggest they draft a regional standard. 2. A quick analysis of another of our members identified 12 generating plant locations (R6.1.3), 18 flowgates (R6.1.4) at 12 locations and one IROL (R6.1.6) location where we own Elements. Presently we are required by SERC to have DDR at 6 locations. This results in the entity possibly needing DDR at 19 additional locations, with a total of 25! Was there any effort, as was suggested in the Atlanta drafting team open forum meeting, for a data request of the REs to assess how many DDRs (Elements) would be need to be monitored? If so where is this information? If this was not done, it must be a part of the cost impact effort. 3. Clarity is needed under Requirement 6.1.3 to understand how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples will be most helpful. 4. Clarity is needed in Requirement 6.1.4 (if it is retained) when you refer to “monitor all Elements of: all permanent flowgates”. If a flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every transformer need to be monitored (lowside or highside side)? Please show some typical examples. 5. Under Requirement 6.1, it may be better to move the minimum quantities Requirements 6.1.1 (minimum 1 DDR per 3000MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the Requirements for 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc…), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable Requirements, and state that additional DDR locations are only needed if fulfilling the first 5 Requirements does not meet the two extra minimum quantities Requirements.
Yes

No
1. Extend the GO 100% requirement to 6 years because it better matches the typical major unit overhaul schedule for the large units and plants that this standard targets. 2. Clearly state that the TO / GO has 3 years to attain 100% for any newly identified locations in the five year review.
We request the SDT to make the following changes: 1. The Requirements of R3, R4, R5 and R12 for SER and FR data should be included as part of a single attachment/ table and R3 should simply reference the table. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation multiple Requirements. 2. Similar to 1) above, Requirements R8, R9, R10, R11, and R12 for DDR data should be included as part of a single attachment/ table or possibly separate attachments/tables for TOs and GOs and referenced in a single Requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation of multiple Requirements. 3. Provide at least one example in the Guidance Section, or develop a reference document similar to the BES Definition effort. A system one line similar to BES Definition Reference Figure S1-1 augmented with circuit breakers in various configurations (e.g. straight bus, ring bus, breaker-and-a-half). The drafting team could go through the various Requirements to demonstrate the SDT intentions. Although the present guidance and rationale are helpful, we believe there are still many unclear aspects to these Requirements. 4. Add ‘by voltage level’ in Requirement R1 so that it reads ‘Each Transmission Owner shall identify BES bus locations by voltage level for Sequence of Events Recording (SOER) and Fault Recording (FR).’ This is consistent with Attachment 1, Step 1 and clarifies that the FR and SOER are only required at that voltage level. 5. In Requirements R1.2 and R 6.2, what prevents a TO or RE from assessing the locations and elements on too frequent of a time basis? As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability in where monitoring is really needed. Frequent assessments could jockey locations above and below the minimum criteria line and create confusion. 6. In Requirement R2, it infers that the TO as part of Requirement R1 develop a list of Elements;, however, Requirement R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest Requirement R2 be reworded to say “Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify…”. If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. Time has to be allotted to allow identifying the Elements at the BES bus locations. Element ownership sometimes changes between the two terminals of an Element, so this needs to be addressed. GO and TO are each concerned with the unwarranted cost burden this standard proposes, and there will be disputes as to cost responsibility. 7. Use a consistent footer (pages 18 through 40 say Draft 1), and number the pages throughout (they stop at page 25 of 40). 8. Clarify the intent of Requirement R3 which we believe is unclear. The drafting team may intend that a breaker auxiliary contact be connected to the SOER to provide circuit breaker position. Page 32 Guideline for Requirement R3 last sentence implies that breaker status can be determined from the FR. However page 33 last sentence under Recording of Electrical Quantities suggest that these only augment the SOER. 9. Add ‘including generator interconnection facilities’ after Transmission lines in Requirement R4 to be consistent with page 32 Guideline and Project 2010-07. 10. In Requirement R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the Requirement. We suggest Requirement R5.1 be reworded to say “A single record or multiple records that include at least one of the following:” 11. Reword Requirement R13 to ‘Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 shall provide data for those BES Elements to the Regional Entity upon request.’ The regions already have a process for collecting these types of data and can act as a clearinghouse if indeed the Reliability Coordinator and/or NERC need the exact same data. The reality is that all these entities will collaborate in the disturbance analysis if an event of this magnitude ever does occur. It is unreasonable to require the TO and GO to respond to duplicative data requests in such a short time. 12. Reword Requirement R14 to ‘Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 upon the discovery

of a failure shall: (a) Restore the recording ability within 120 calendar days; or (b) If recording ability is not restored within 120 calendar days, demonstrate efforts to correct the unresolved failure.' Please increase the allowed repair time by 30 days because the access of repair personnel to such equipment is often restricted during certain periods of the year. In addition; revise the second part to be consistent with the handling of Unresolved Maintenance Issues in PRC-005-2 R5. This change triggers an M14 part (3) change to "(3) if not repaired within 120 calendar days of discovery, evidence that it has undertaken efforts to correct the unresolved failure Issues in accordance with Requirement R14. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.' We believe that the proposed reporting requirement is much too burdensome for this equipment.
Individual
Angela P Gaines
Portland General Electric Company
No
Portland General Electric Company (PGE) appreciates the standard drafting team's efforts in crafting this proposed standard and understands the importance of the data that will eventually be available once the standard is implemented. However, a four (4) year implementation window may not be enough time if an entity is required by its Responsible Entity (in our case, the RC) to install several disturbance monitoring units. It is interesting to note that an entity that has only one element to implement has the entire 4 year window to do so. However, if an entity has 2 elements, for example, that entity does not get 8 years to implement but, in effect, has half the time. The more elements required to be implemented, the less overall time an entity has to do so. PGE suggests letting the RC develop an implementation timeframe based on the elements it determines an entity needs to install. Depending on the number of elements required, an entity would be considered compliant as long as it was meeting specified and agreed upon milestones. The triggering of the negotiated timeframes could be based on a pre-determined number of elements, i.e. >4, or on a business-justified request from the entity for an extended implementation window. To suggest that an entity is non-compliant because all necessary projects are not fully completed after a 4 year implementation window fails to distinguish between entities that have taken no action whatsoever and entities that have projects and activities in progress well ahead of the effective date of this proposed standard.
Individual
Anthony Jablonski
ReliabilityFirst
Yes
No
Requirement R1, Attachment 1 - ReliabilityFirst questions the rational to not require any Fault Recording and Sequence of Events Recording if there are no buses that fall on the list (i.e. an entity has no buses with maximum available calculated three phase short circuit MVA of 1500 MVA or greater). ReliabilityFirst believes to effectively recreate events using Fault Recording and Sequence of Events Recording data, Transmission Owners that have no buses on the list should still be required, at a minimum, to have at least one BES bus location with Fault Recording and Sequence of Events Recording. It could be required at least one BES bus location with the highest maximum available calculated three phase short circuit MVA. In order to achieve this, ReliabilityFirst

recommends the first sentence in Step 7 ("If there are no bus locations on the list: the procedure is complete and no Fault Recording and Sequence of Events Recording will be required. Proceed to Step 9."), be removed from the methodology. Also, even though ReliabilityFirst believes the template for determining Fault recorder and SOE bus locations is helpful, ReliabilityFirst recommends developing a step by step example detailing the locational selection methodology.
No
Applicability - ReliabilityFirst understands the rationale behind differentiating the Responsible Entity per Interconnection, but does not agree with ERCOT still stating "Planning Coordinator or Reliability Coordinator". ERCOT is both the Planning Coordinator and Reliability Coordinator so the SDT needs to decide which function in ERCOT will be responsible for determining DDRs to avoid any future confusion for monitoring compliance.
No
Requirement R6, Part 6.1.3.2 - For Requirement R6, Part 6.1.3.2 ("Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA), does this mean only individual units which are greater than 300 MVA and part of plant need to have DDRs? If this is the case, it appears that a plant that has five 200 MVA units does not require DDRs. Is this the SDTs intent? ReliabilityFirst believes any plant/facility that has an aggregate nameplate greater than 1000 MVA, should have equipment capable of DDR.
No
VSL for Requirement R3 (the same rationale in this comment also apply to the VSLs for Requirement R4,R5, R8, R9, R10 and R11) - ReliabilityFirst believes the gradation of VSLs should be in 10% increments (or similar to the VSL designations for Requirement R1). For example, if an entity only implemented 59% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers, this does not meet the intent of the requirement and therefore should be a "Severe" VSL.
Requirement R4, Part 4.2.1 - With the forthcoming approval of the NERC BES Definition including "Transformers with the primary terminal and at least one secondary terminal operated at 100 kV…", ReliabilityFirst does not believe the informative language in Requirement R4, Part 4.2.1 is needed and recommends removing the following language from Requirement R4, Part 4.2.1: "that have a low-side operating voltage of 100kV or above" since it serves no purpose. Requirement R14 - ReliabilityFirst does not believe there is any value for an Entity to report their inability to record data (due to a failure of a FR, SOER or DDR) to the Regional Entity. ReliabilityFirst believes the record keeping will be burdensome with little or no benefit. ReliabilityFirst would rather like to see the Entities get the corrective actions plans in place and the equipment fixed, thus the Regions really have no need for this type of report. Compliance can be monitored through a data submittal on an annual basis rather than an ongoing reporting requirement. Also, even though a bulleted list in a Reliability Standard indicates an "or" statement, it is still unclear that these are considered two options. ReliabilityFirst recommends adding the word "either" after the word "shall" in the parent Requirement R14 and including the word "or" after the word "ability" in the first bullet. ReliabilityFirst also recommends the following to remove the Regional Entity from the second bullet and adding a timeframe for when the CAP needs to be completed (it should not be open ended): "Develop and implement a Corrective Action Plan (CAP) to restore the recording ability within xx days." Also, the CAP should not have an open-ended timeframe for completion, such as years into the future. There needs to be some time limit for correction.
Group
SPP Standards Review Group
Robert Rhodes
No
To maintain parallel structure in the definition of Dynamic Disturbance Recording (DDR) we suggest changing 'abnormal voltage problems' to 'abnormal voltage deviations'. The acronym for Fault Recording (FR) may be confused with that of Frequency Response as has been previously defined in BAL-003. Would it be prudent to change one or the other? Insert 'which' in the next to last line of

the Rationale Box such that it reads '...proliferation of multiple function devices, and the intent of the Standard which is to address the result, not the how...'
Yes
Insert an 'a' in the 6th line of the 2nd paragraph of the Rationale Box such that it reads '...have a significant effect on system reliability and performance. Conversely, locations with a very low short...' We suggest the drafting team watch for consistency in the use of the adjective 'three-phase' throughout all the posted documents. Make sure it is properly hyphenated.
Yes
We thank the drafting team for deleting the Reliability Coordinator as an Applicable Entity in the Eastern Interconnection.
No
Requirement R6.1.3.2 requires DDR for all generating units greater than 300 MVA at a plant/facility with an aggregate nameplate rating equal to or greater than 1000 MVA. Does this apply in situations where the generating units may be connected at different voltage levels within the plant/facility? Especially those which may not even be tied together within the plant/facility? Requirement R6.1.4 requires DDR for all permanent Flowgates within the Eastern Interconnection. We believe this requirement is troublesome for several reasons. First, Flowgates can be added on the fly in Real-time. Although these Flowgates are at that time temporary, they can become permanent at the end of the month in which they were created in the Book of Flowgates. Thus a Transmission Owner would then be responsible for having DDR equipment on that Flowgate within less than 30 days. This is an unreasonable request. Additionally, most Flowgates are thermally limited and not all of them represent facilities which have a significant impact on the BES. They may have been created to address localized loading issues. As such, requiring these facilities to be monitored by DDR equipment is excessive and does not contribute significantly to the reliability of the BES. On the other hand, there may be other Flowgates which do consist of or represent facilities which can have a tremendous impact on the BES. Some of these Flowgates are there specifically to address voltage stability and dynamic system stability issues. These facilities need to be monitored by DDR equipment. The difficulty becomes determining which Flowgates fit the latter category. The drafting team needs to put some effort into determining the criteria to use in deciding which Flowgates are worthy of DDR monitoring.
Yes
We note in several of the Severe VSLs that quantifiers of greater than 0% but less than 10% are used. However, in Requirement R11, the quantifiers are greater than 1% but less than 10%. Was the 1% intended or should it have also been 0%?
Requirement R2 calls for Transmission Owners to notify other owners (who would also be Transmission Owners) of other facilities within the locations identified in Requirement R1. There could conceivably be situations where multiple owners would be involved and possibly none of the owners was able to identify 11 locations as specified in R1. In this situation, those particular facilities would not be required to have SOER or FR equipment even though the impact of those facilities could be significant on the BES. While this situation may be very unlikely to occur, it is still a possibility. In Requirement R2 and its associated Rationale Box as well as throughout the posted documents, check for hyphenation of terms such as 90-calendar days, 60-calendar days, 30-calendars days, etc. In the Rationale Box for R8 modify the single-line, paragraph to read 'Because all of the buses within a location are typically at the same frequency, one frequency measurement is adequate.' In the 1st paragraph under the Guideline for Requirement R1 section in the Guidelines and Technical Basis, modify the next to last line to read '...voltage and current for individual circuits allow precise reconstruction of events of both...'. Check the usage of wide-area and make sure it is properly hyphenated throughout the standard and the posted documents. Something appears to be missing in the 2nd sentence in the last paragraph under the Guideline for Requirement R1 section in the Guidelines and Technical Basis. 'Five years is long enough to avoid unnecessary, but long enough to adapt...'. To avoid unnecessary what? In the 1st line of the 2nd paragraph under the Guideline for Requirement R5 section in the Guidelines and Technical Basis, change 'Pre and post...' to 'Pre- and post-...'. In the 2nd line of the same paragraph, change 'SOE' to 'SOER'. In the 6th and 8th lines of the same paragraph, hyphenate '50-cycle post trigger'. In the 2nd line of the 4th paragraph under the Guideline for Requirement R5 section in the Guidelines and Technical Basis,

replace ‘Oscilloscope’ with ‘oscilloscope’. In the 7th line of the 4th paragraph under Guideline for Requirement R6 section in the Guidelines and Technical Basis, modify the line to read ‘…interfaces are defined by the Regional Entity. In the ERCOT and Quebec Interconnections, the…’. In the Guidelines for Requirement 7 and Requirement 12 in the Guidelines and Technical Basis, the reader is referred to the Rationale Boxes in the standard for the information on those requirements. Once the standard is approved, the Rationale Boxes will disappear. We suggest going ahead and inserting the material from those boxes here even if it is redundant. In the 1st line of the 1st paragraph under Guidelines for Requirement R8, revise the line to read ‘Dynamic Disturbance Recording measures transient response to system disturbances after a fault is…’. In the 3rd line of the 1st paragraph under Guidelines for Requirement R10, revise the line to read ‘…analysis. Pre- and post-contingency data help identify the causes and effects of each event…’. Modify the 1st line of the 1st paragraph under Guidelines for Requirement R11 to read ‘Dynamic Disturbance Recording contains the dynamic response of a power system to a…’ or ‘Dynamic Disturbance Recording contains the dynamic response of power systems to a…’. In the 3rd line of the same paragraph hyphenate ‘short-term’ and ‘long-term’. In the 4th line of the same paragraph delete the ‘the’ such that the line reads ‘…interest is changing over time, Dynamic Disturbance Recording is normally stored in the…’. We suggest the following to replace the 1st sentence in the 1st paragraph in the Guideline for Requirement R13: ‘This requirement directs the applicable entities, that upon requests from the Reliability Coordinator, Regional Entity or NERC, to provide SOER and FR data for locations determined in Requirement R1 and DDR data for Elements determined in Requirement R6. Replace ‘was’ with ‘were’ in the 4th line of the 6th paragraph in the Guideline for Requirement R13 section of the Guidelines and Technical Basis. We suggest the drafting team number the pages in Attachment 1 and the Guidelines and Technical Basis document.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
AECI Supports comments posted by SERC PCS In addition, AECI particularly questions the value and technical rationale for citing all permanent flowgates. There are several types of permanent flowgates, and not all would correlate to the BES Reliability purpose to warrant DDR measurements at either end. Is it this SDT's intent to move the Eastern Interconnection away from flowgate methodogy for assessing impact and capacity for commerce across its bulk transmission system? If the other specified technical assessments have merit, then busses terminating any flowgates significant for DDR will show up.
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
City of Austin dba Austin Energy (AE) believes that the proposed PRC-002-2 standard is overly prescriptive and provides unnecessary requirements that are already addressed by Regional rules, guidelines, requirements, etc. For example, ERCOT has requirements for installing Disturbance Monitoring Equipment (DME) that may address more specific regional needs, considering ERCOT system characteristics. Additionally, AE believes the standard, as proposed, would be costly to implement.
Group
Bureau of Reclamation
Erika Doot

Yes
Yes
Yes
Yes
Yes
Yes
Individual
Karin Schweitzer
Lower Colorado River Authority
Yes
Yes
Yes
No
Not cost-effective based on cost of improvements vs. benefit. TO installations adequately address requirement. VRFs are all in the "Lower" range which supports the fact that the requirements are unnecessary. Reference recent actions related to Paragraph 81.
Yes
Yes
R3 – clarify if EMS/RTU or Plant DCS circuit breaker timestamps will meet this requirement. R3, R4, R5, R11, R12, R13, R14 – Clarify "AND" in requirement and "OR" in measure – language is confusing. It is inconsistent. R5 – Change 5.1 minimum length from 50 to 30 cycles. An excessive number of events can cause data to be overwritten and can delay the downloading of data. Change 5.3 to "Trigger settings for at least one of the following:" –OR– remove Phase undervoltage as a trigger requirement. R13 – revise 13.2 from a minimum of 10 calendar days down to 5 calendar days. Longer-term storage of data may be difficult with a large number of SOER/FR/DDRs on your system. R14 – change minimum response time from 90 calendar days to 180 calendar days to allow for design, procurement, and installation of long lead-time equipment/components used for SOER/FR/DDR.
Group
Santee Cooper
S. Tom Abrams
No
We agree with the SERC PCS comments.

Individual
Martyn Turner
LCRA Transmission Services Corporation
Yes
Yes
Yes
No
Not cost-effective based on cost of improvements vs. benefit. TO installations adequately address requirement. VRFs are all in the "Lower" range which supports the fact that the requirements are unnecessary. Reference recent actions related to Paragraph 81.
Yes
Yes
R3 – clarify if EMS/RTU or Plant DCS circuit breaker timestamps will meet this requirement. R3, R4, R5, R11, R12, R13, R14 – Clarify "AND" in requirement and "OR" in measure – language is confusing. It is inconsistent. R5 – Change 5.1 minimum length from 50 to 30 cycles. An excessive number of events can cause data to be overwritten and can delay the downloading of data. Change 5.3 to "Trigger settings for at least one of the following:" –OR– remove Phase undervoltage as a trigger requirement. R13 – revise 13.2 from a minimum of 10 calendar days down to 5 calendar days. Longer-term storage of data may be difficult with a large number of SOER/FR/DDRs on your system. R14 – change minimum response time from 90 calendar days to 180 calendar days to allow for design, procurement, and installation of long lead-time equipment/components used for SOER/FR/DDR.
Individual
John Brockhan
CenterPoint Energy Houston Electric
Yes
Yes
Yes
No
CenterPoint Energy understands the potential usefulness of dynamic data for event analysis and supports the collection of dynamic data for event analysis as a Best Practice. However, the Company's experience has been that sufficient data for event analysis is available from existing fault recording devices and therefore is strongly opposed to inclusion of a requirement to provide dynamic data. The only way to provide dynamic data is through a dynamic recording device. If an entity does not currently have any dynamic recording devices installed on its system then the entity has little choice but to spend capital in order to acquire and install these devices to comply with the Requirement. CenterPoint Energy does not believe the enabling legislation allows for Reliability Standards to require the expenditure of capital funds. While the SDT contends the requirement is only for dynamic data, not the installation of dynamic recording devices, and an entity is free to determine how it will comply, CenterPoint Energy finds this argument disingenuous. CenterPoint

Energy strongly recommends the deletion of this requirement. The Company cannot support any draft Standard that contains such a requirement.
No
CenterPoint Energy is concerned the proposed Implementation Plan does not allow sufficient time for entities to make arrangements with other entities or, if needed, to install required devices or communication devices. Based on Requirement R6 the ERCOT Region would require approximately 18 – 20 DDR's and several times that amount of SOER's. The installation of DDR's and SOER's would require scheduling outages on possibly hundreds of pieces of equipment. The scheduling and coordination of this amount of planned outages is simply not possible within the allotted timeframe. CenterPoint Energy recommends expanding the Implementation Plan to three to five years.
1. CenterPoint Energy believes the intent of some of the requirements is unclear without the corresponding Rationale box. It is our understanding that auditors may consult the rationale and other information to be placed in the Application Guidelines section; however, auditors must always refer to the requirement language. Therefore, the language of the requirements should clearly explain the intent of the requirement with less reliance on the Rationale boxes. For example; Requirement R13.2 should identify the data retrieved as only the data measured within 10 days preceding a request. Recommend modifying Requirement 13.2 to read "Only recorded data measured and recorded within 10 days prior to a request will be retrievable." The Rationale box for R13 clarifies the intent of the requirement; however the language should be more specific. The language for requirement R14 should explicitly identify the sub-bullets as an "or". Furthermore, CenterPoint Energy recommends modifying the second bullet of Requirement R14 to read "If the recording ability cannot be restored within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability."
Individual
Steve Hill
Northern California Power Agency
Yes
No
Seems excessively tedious for all TOs. Transmission Owners need to produce Transmission Studies per TPL standards. Steps 1 & 2 can be obtained from those studies. Steps 3&4 and second paragraph of step 7 seem arbitrary. Why 11? Please justify the second paragraph of step 7.
No
WECC has a Synchrophasor program. Why would not the RE or the appropriate RC identify the areas where this equipment is located and continue with the existing program?
Yes
Generally yes; however this should be consistent with WECC's continued synchrophasor program
No
No because I do not support the registraton process
No
I do not agree with the registration
I support the comments of FMPA from Frank Gaffney
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC PCS
Individual
Christina Conway
Oncor Electric Delivery

Yes
Yes
Yes
No
The R6.1 sub-requirement describes minimum locations. There are no limitations on the DDR requirements written into the standard language. This could potentially lead to the Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) overburdening the TO/GO with the volume of included locations. The language in R1 provides a “20%” audit curtailment for the FR/SOER but there is no similar language for the DDRs in R6.
Yes
Yes
General: Oncor identified several instances where the Rationale Boxes provided much needed clarity to the Requirement itself. It is understood the Rationale Boxes will be retained but relocated to the Application Guidelines Section of the Standard. However, incorporating the Rationale/intent language into the Requirement itself would further clarify the Requirements resulting in a clear and mutual understanding for both the Registered Entity and the auditor(s). Therefore Oncor recommends the Standard Drafting Team review the Requirement language and the corresponding relocated Rationale language to ensure there are no gaps once moved to final state. Additional details provided below. R1: To clarify the line/bus distinction, Attachment "BES Sketches - Facility Example & Boundary Definitions" should be added to the Standard. R2 and R6.2: The Implementation Plan includes specific references to timeframes for becoming fully compliant with the locations lists, but the Requirement language itself does not include post-implementation compliance timelines for the required reassessments. The Implementation Plan states "Entities shall be 100% compliant with a reassessed list from Requirement R1, Part 1.2 or R6, Part 6.2 within three (3) years following notification of the list." This language should also be included in the language of the affected Requirements to prevent any disparity following the initial implementation and departure from the Implementation Plan. R3: Legacy FR equipment installed before the standard effective date may not be capable of embedded SOER. R3 does not afford the same caveat for older equipment where SOER is required that R10 provides for older equipment where DDR is required. Language should be added to R3 providing the option to utilize FR digitals to monitor circuit breaker position for each circuit breaker. R4 and R8: Add Rationale box stipulation that the required “electrical quantities, whether directly measured or derived,” to R4 and R8 as described below: The R4 Rationale Box explains the method of deriving electrical quantities; however, the requirement language of R4.1 does not reflect the intent described in the Rationale Box. Specifically, whether or not locations where busses are effectively tied together, such as on ring or breaker-and-half bus configurations, can derive the required phase-to-neutral voltages by monitoring a minimum of two of each phase-to-neutral voltages, from either line terminal or bus potentials. In a typical large switching station, this could eliminate costly retrofits to literally provide all three phase-neutral voltages for “each line or bus.” The language of R8.3 does not specify the method used to provide “Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.” If the intent follows the electrical quantity collection of R4, the language of R8 should also specify the ability to derive electrical quantities. Allowing calculated power flow would prevent costly retrofits to literally provide 6 dedicated analog traces for each Element required to have a DDR. R10: The language of R10 could be interpreted to mean the triggering requirements are only applicable to DDR equipment installed prior to the effective date of the standard. The triggering requirements are applicable to all DDR equipment. Additionally, the collection of 3-minute FR records for every transient event as a substitute for a DDR is a costly modem transfer and storage retention practice. R11: If relays meet the requirement of a DDR, the language of R11.1 or M11 should specify that synchrophasor data is acceptable for DDR analysis. R12: The language of R12 should provide a caveat to allow for manipulating event records to UTC

for equipment that is synchronized but cannot time-stamp with UTC as the reference. This would be similar to the “or derived” language suggestions to Requirements R4 and R8 which would allow for legacy equipment to meet the standard as well as allow for the time-alignment for multiple FR/SOERs as M12 evidence. Additionally, Rationale box language, further explaining the UTC local offset, should be included in M12 to clarify that offset records are acceptable as evidence. In other words, requested records must be supplied in UTC format, but the stored format does not need to adhere to UTC format. R13: Some entities do not automatically name files in the COMNAME format for ease of data storage. With the phrase “formatted records,” M13 implies that manipulation of file before submittal is allowed. If data file names can be changed to the prescribed COMNAME formatting, R13.5 should specify that the data files need only be provided in this format rather than originally named this way.
Individual
Michael Moltane
ITC
Yes
Yes
Yes
No
6.1.4 for Eastern Interconnection “permanent Flowgates” rather than using a blanket approach to require DDR on all defined Flowgates, they should be selectively placed on those Flowgates that have a chronic congestion history. The DDRs should be placed on the defined monitored element(s) of permanent flowgates that exhibit a history of chronic congestion
Yes
Yes
R4, R11, R12, R13 and R14 need to be clear that they apply to the Element and/or equipment owner. They will be acceptable if they are reworded as: R4 after “following electrical quantities” insert “for each of the Elements they own” R11 after “for the Elements” insert “they own” R12 and R13 after “Dynamic Disturbance Recording (DDR) data for” insert “for Disturbance Monitoring Equipment they own” R14 after “or Dynamic Disturbance Recording (DDR)” insert “that they own”
Group
Bonneville Power Administration
Andrea Jessup
No
BPA feels the definitions are not succinct enough to explain to someone exactly what it is they’re being required to do.
Yes
No
BPA feels that responsible functional entities — as well as roles and responsibilities — must be clearly identified in the Standards and requirements. As the Standard is currently written, BPA feels that too much credence is given to assumptions outlined in the Standard and, unless clearly defined, these assumptions will not pan out as described.
No

a) BPA feels there should not be a requirement to monitor all elements of a path/interface/IROL when three of five lines can supply enough understanding (used in conjunction with other DME); and b) The IROL should be determined by Planning Criteria, not by a dynamic/ever-changing IROL.
No
BPA feels that R6 should remove “x percent” of the identified Elements (or Busses) and keep the time-based VSL.
Yes
A. Introduction 4. Applicability 4.1 The Responsible Entity is: BPA feels that under this section planning coordinators and reliability coordinators are named as the responsible entities which are later tasked with determining the necessary locations for dynamic disturbance recording equipment. This was one of the primary issues with the previous version of the standard, PRC-018. These entities failed to write such standards and therefore the standard lacked the necessary content for transmission and generation owners to apply. This basis will face similar challenges. Additionally this delineation of the responsible Entity takes authority away from the TOs and GOs to operate their monitoring systems in a way that makes good financial and operational sense for their individual companies. This definition should also be expanded to include Transmission Operators and Generation Operators. B. Requirements and Measures R1. BPA feels the substance of this section is based on the Attachment 1, which is later labeled as Attachment A, so it is on that section that comments shall be provided. The methodology presented in Attachment 1 is overly complex and does not present a sound technical basis for the location of DFRs and SERs. Monitoring locations above 1500MVA are subject to selection based on mathematical manipulation for which no system impact basis is provided. A final step of “engineering judgment” is then applied in order to round out the list. This methodology may not result in consistent or repeatable bus selection for the placement of DFRs and SERs and will be difficult to defend in an audit scenario. This use of an MVA based location criteria is not consistent with other system impact based criteria currently being used within the NERC standards, such as CIP-002-4 & 5, nor with draft versions of the WECC disturbance monitoring standard. R2. BPA feels this requirement places a compliance burden on the Transmission and Generation owners for equipment over which they have no control. TOs and GOs might be responsible for bus identification and notification of other entities with interconnections to those busses but the identification of individual BES elements and the associated compliance burdens should be left to those with operational responsibility for those elements. R3. BPA feels this requirement refers to R2 in the text I believe this reference should be to R1 as R2 does not define bus locations. R4. BPA feels that this requirement needs to be clarified. Specifically, BPA feels that not all line voltages are required if there is no bus (with two lines minimum). R5. BPA feels that in sections 5.1 and 5.2 specific record lengths and sample rates are delineated. The standard goes too far in mandating equipment specification for the Transmissions and Generation owners. The development of equipment specification must be left to the individual owners and operators in order for them to effectively balance cost and operational requirements. R6. BPA feels the responsibility for the sighting of DDRs should be assigned to the Transmission/Generator Operator/Owner not the reliability coordinator. The Operator/Owner must be left to identify BES elements which require dynamic disturbance recording equipment. This may be easily and consistently accomplished through the application of bright line criteria. The criteria provided in 6.1 are insufficient. The criteria do not account for operating voltage or equipment such as series capacitor installations which could contribute to sub synchronous resonant situations. A comprehensive set of bright line criteria for DFRs, SERs, and DDRs must be developed. These criteria should be consistent with similar criteria used in other NERC and industry standards. Any list of locations which is delineated by a Responsible entity must be subject to some adjustment by the affected TO or GO. R7. BPA feels the Transmission/Generation Owner/Operator must be responsible for the identification of locations which require DDRs not the Reliability Coordinator. Only in this manner may the individual TOs and GOs achieve visibility of their own systems. R14. BPA feels the requirement needs to clearly indicate that it is an “OR” distinction between the two bullets. So that one-hour or one-day equipment reporting and corrective action plan is not required at the time of discovery, but rather (as is intended) only after 90 days of failure.
Group
Colorado Springs Utilities

Kaleb Brimhall
No
No
No
No
Yes
As shown in the VRF levels (all "lower"), we do not believe that there is sufficient reliability justification to make this a standard.
No
Thank you standard drafting team for all of your efforts. We believe that all of the disturbance monitoring equipment referenced in this standard can be very helpful to an organization. We do not believe that it has a reliability impact that merits the cost in time and money to install, maintain, and report on all these devices as specified in the standard. As shown by the VRFs this does not highly impact reliability and although disturbance monitoring is something that could be useful, at times, should not be part of a mandatory standard. If a standard is to be implemented, we view the approach as written, to be too broad and cumbersome. We would recommend that a technical criteria based on system configuration be established to identify critical points for disturbance monitoring (DM) and that DM be implemented at those locations. We believe a more focused and technically based approach to placement of DM equipment would yield higher benefits while eliminating unnecessary and undesirable impacts.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
We believe the "Responsible Entity" should be consistent across the Interconnections. We recommend changing this to be the Reliability Coordinator for all Interconnections.
Yes
We agree, however some clarity should be added: 1) In R6, mention is made of both Elements and locations for locating DDR. Is the intent to have the location be an entire substation, an entire bus, or a single Element? Or is that entirely at the discretion of the Responsible Entity? 2) R6 refers to generating resources with individual nameplate capacities. For a combined cycle plant, does the individual nameplate capacity of the resource refer to the combined unit or the individual turbines? Recommend making this more clear. 3) Is the list in R6 intended to be an all-inclusive list or is it a minimum list? If it is a minimum list, there is a concern that the standard may allow one entity to put increased costs on another entity, for example a Reliability Coordinator that wants a DDR on every generator, regardless of size. We ask the drafting team work to address this issue. We recommend that the drafting team determine the list of places that need a DDR and redraft the requirement to eliminate the responsible entities of the RC and PC and instead just require the owner of elements that meet the specifications install DDRs.
No

1) Our concern with the implementation plan is that its milestone requirements are significantly different from requirements for similar equipment in PRC standards that are now awaiting final FERC approval. Specifically, PRC-019, PRC-024, & PRC-025 involve the same facilities and all have 5 year implementation plans (with some caveats). Yet the implementation plan for PRC-002 is 4 years. When entities are considering work planning and execution, it would be more efficient to provide an implementation schedule that allows 'campaigns' at generation facilities to address all of the protective system equipment changes due to the suite of PRC standards under one maintenance project. (This is especially critical when considering this work will likely require an outage.) Therefore, Xcel Energy recommends PRC-002 utilize the same phased in schedule as PRC-019, PRC 024 and PRC-025. At a high level, the modification would be to change the implementation plan to: [Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13: -Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that additional equipment is not necessary, the first day 60 months from notice of applicability of R1 or R6. -Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that additional equipment is necessary, the first day 84 months.] 2) Finally, the standard is written such that the requirements are phased in over time. However, there is no period identified for the TO or GO to become compliant after any change in the points identified. As an example, in 2020, if the TO determines in R1 that a new point needs a device, R2 allows them 90 days to notify the owner of that equipment. Yet, for R3, R6 and R7 there is no established period of time for the TO or GO to make such an installation. We recommend the drafting team add in an implementation period for newly identified points beyond the immediate phased-in implementation of the standard.
1) It appears that a lot of individual requirements are written for something that isn't overly complex. Please consider consolidating R8-R11, or consolidating the technical specs that comprise R5, R11, and R12. 2) In R14, its not clear why the Regional Entity is introduced here. Also, the Regional Entity would take on the burden of tracking corrective action plans, if the recorder isn't restored in the 90 day period. Recommend changing Regional Entity to Reliability Coordinator.
Group
Western Area Power Administration
Lloyd A. Linke
Yes
Yes
Would like more information as to how the 1500 MVA value was decided upon.
Yes
No
DDR installations have been resource intensive and problematic to install and to place on-line. Section 6 opens the door for quite a number of DDR deployments. Section 6.1.4 requires the monitoring of all Elements of major transfer paths on the Western Interconnection. Utilities in the Western Interconnection have already participated in WECC's WISP program and have installed and commissioned DDR's as required. DDR deployment per WISP should be considered sufficient in the WECC footprint.
Yes
Yes
Overall, the implementation program appears reasonable. However, the work involved is linked to the requirements of the standard which could possibly change. The requirements of R6 may be difficult to meet as written. See comments under Question 4.
Section 5.3 – Disagree with the trigger requirements as written. There are many factors that contribute to effective triggering such as: • Triggering for local vs. remote faults • Avoiding over-triggering that could result in "information overload" and the filling up of data storage • Capturing relevant and complete fault representation The requirements stated are inadequate. It is felt that trigger settings are best left to the professional judgement of the relay engineer. While triggering on

Neutral (residual) overcurrent is often standard, care must be taken regarding the sensitivity level. Similarly, triggering issues related to sensitivity and pickup time are associated with phase undervoltage triggering. Other triggering methods (such as based on protection element pickup) may be preferred instead of undervoltage methods. Section R13 – the requirements of R13.4 and R13.5, while achievable, are somewhat archaic. More flexibility should be allowed for frequently used, industry standardized fault recording formats such as SEL event records. Also, the naming convention put forth in C37.232 is not the easiest to follow.
Individual
Russell Noble
Cowlitz PUD
Agree
FMPA's comment submitted by Frank Gaffney

Consideration of Comments
Project 2007-11 Disturbance Monitoring

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

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

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

Summary Consideration

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

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

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

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

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

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

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

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

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

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

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

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

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

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

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

Additional Member	Additional Organization	Region	Segment Selection
8. Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6

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

No Additional Responses

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

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

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

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

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

No Additional Responses

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

No Additional Responses

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

No Additional Responses

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

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

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

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

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

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

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

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

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

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

8. Don Cuevas	Beaches Energy Services	FRCC	1
9. Mark Schultz	City of Green Cove Springs	FRCC	3

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

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

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

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

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

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

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

No Additional Responses

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

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

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

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

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

No Additional Responses

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

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

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

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

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

4. Dana Showalter	E.ON Climate & Renewables	ERCOT	5
5. Joe O'Brien	NIPSCO, Hammond	RFC	5

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

	Additional Member	Additional Organization	Region	Segment Selection
11.	DAVID GREENE	SERC RRO		
12.	DAN ROETHEMEYER	DYNEGY		

				1	2	3	4	5	6	7	8	9	10
27.	Group	Wayne Johnson	Southern Company	X		X		X	X				

No Additional Responses

				1	2	3	4	5	6	7	8	9	10
28.	Group	Robert Rhodes	SPP Standards Review Group		X								

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Organization	Yes or No	Question 1 Comment
		We don't see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis. We could support the definitions as used within this standard but do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR. Since this is a data standard, strong consideration should be given to using the word "data" in place of the word "recording", such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD. Also the definition of SOER presently uses the phrase "... status of Elements, which may include protection and control devices." We recommend changing the word "Elements" to "circuit breakers" which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status.
Response: The DMSDT believes that having SER and FR data as specified in the current draft of the Standard is sufficient for understanding the nature of a large scale power system disturbance and for effective post-event analysis. NERC's Event Analysis group reviewed and agreed with this approach proposed by the DMSDT. Having precise information on sequence of operation of protection equipment may be of interest for detailed analysis of protection system performance. Having such capability is a technical and business decision that is left up to the individual Entities to make. **In response to numerous comments, the DMSDT has agreed to remove the definitions from the draft standard.**		

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Response: The Responsible Entity is used in this standard to refer to either the Planning Coordinator or Reliability Coordinator (NERC registered entities) based on Interconnection. This is detailed in the Applicability Section 4 of the Standard. This helps simplify the requirement verbiage and application to each Interconnection.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>addresses phasing in of the standard, or new version of the standard, not ongoing implementation.</td></tr>
<tr><td colspan="3">Response: The Implementation Plan is approved in the same manner as the standard. It is balloted along with the standard, approved by the BOT and filed with regulatory authorities simultaneously with the standard. The Implementation Plan and its provisions will remain separate from the standard.

The following has been added to the end of the Implementation Sections:

Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.</td></tr>
<tr><td>Ameren</td><td>No</td><td>We request the DMSDT to make the following changes:

(1) Add 1 month to item 3 for the TO to identify BES Elements in R1.

(2) Delete ‘bus locations and’ in item 6 so that the total percentage (%) is based on BES Elements throughout the Implementation Plan. There are bus locations at which there are several different owners of the BES Elements.

(3) Replace ‘24 months or more’ with ‘up to 60 months’ in item 9.

(4) The Implementation Plan Summary is very helpful but the Entity is incorrect for R8, R9, and R10.</td></tr>
<tr><td colspan="3">Response:

1) The DMSDT believes that there is sufficient time to implement the standard.</td></tr>
</table>

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

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

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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to:
At least 50% compliant within four (4) years of the Effective Date of PRC-002-2
100% compliant within six (6) years of the Effective Date.

Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>We do not agree based on our earlier comments in regards to Attachment 1.</td></tr>
<tr><td colspan="3">Response: Please see the DMSDT response to those comments in Question 2.</td></tr>
<tr><td>Liberty Electric Power LLC</td><td>No</td><td>See the NAGF SRT comments. Smaller entities who may have one SOE system to install will be forced to comply 100% within two years.</td></tr>
<tr><td colspan="3">Response: The DMSDT has revised the Implementation Plan for Requirements R3 (now R2), R4 (now R3), R5 (now R4), R8 (now R6), R9 (now R7), R10 (now R8), R11 (now R9), R12 (now R10) and R13 (now R11) to:
At least 50% compliant within four (4) years of the Effective Date of PRC-002-2
100% compliant within six (6) years of the Effective Date.

Note: Entities that own only one (1) identified BES bus , BES Element, or generating unit shall be 100% compliant within six (6) years following notification of the list.</td></tr>
<tr><td>Manitoba Hydro</td><td>No</td><td>The times for meeting requirements R1 and R6 are adequate.
However, the time of 9 months required for complying with requirements R2, R7 and R14 is too short, especially considering that R14 may require troubleshooting, testing,</td></tr>
</table>

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

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

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

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

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

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

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>equipment is not necessary, the first day 60 months from notice of applicability of R1 or R6.-Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that additional equipment is necessary, the first day 84 months.]

2) Finally, the standard is written such that the requirements are phased in over time. However, there is no period identified for the TO or GO to become compliant after any change in the points identified.

As an example, in 2020, if the TO determines in R1 that a new point needs a device, R2 allows them 90 days to notify the owner of that equipment. Yet, for R3, R6 and R7 there is no established period of time for the TO or GO to make such an installation.

We recommend the DMSDT add in an implementation period for newly identified points beyond the immediate phased-in implementation of the standard.</td></tr>
<tr><td colspan="3">Response:

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

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

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

2) The Implementation Plan provides three years for TO or GO to be 100% compliant with a reassessed list.</td></tr>
<tr><td>Colorado Springs Utilities</td><td>No</td><td></td></tr>
</table>

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

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

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

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

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

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

Organization	Question 7 Comment
Texas Reliability Entity	(1) For Requirements R2-R5 at substations where there are multiple Transmission Owners, are entities allowed to use a shared FR/SOER, or is each entity individually responsible for the Elements that they own? (2) For Requirement R14, there appears to be an "or" missing following the 1st bullet, "Restore the recording ability, or". The DMSDT may want to consider having the entity reporting DDR failures report to the Responsible Entity as well as the Regional Entity, so that the Responsible Entity can look at possible alternative methods to monitor the Elements required per R7.

Response: (1) The Transmission Owners are allowed to use shared FR/SOER (now SER). The Transmission Owner of the Element for which data is to be captured is responsible for the capture of that data. The standard addresses "what" data must be captured, not "how" it is captured.

(2) A list with bulleted items is an "Or" list for the bulleted items.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Organization	Question 7 Comment

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

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

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

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

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

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

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

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

Organization	Question 7 Comment
	the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES radial lines, or distribution transformers connected to the bus. (4) Requirement R9 should be re-written as follows: Each Generator Owner shall have Dynamic Disturbance Recording (DDR), for each BES Element they own as per Requirement R7, to determine the following electrical quantities. The term BES must be added to provide clarity and be consistent with the intent of the standard as detailed in the Guidelines and Technical Basis section. There is no need to provide monitoring on non BES station service transformers connected to the bus. (5) Requirement R13 Part 13.2 poses an indeterminate requirement on the size of the hard drive required to archive data. The present requirement states that the data will be retrievable for the period of 10 calendar days preceding a request. However, there is no requirement on how long after an event the request might be made. If the request was not made until six months after the event, would the data have to be retrievable for six months after the event? In order to place certainty on this data storage requirement Part 13.2 should be re-written as follows: The recorded data will be retrievable for a period of 10 calendar days following an event. This places a limit on data storage capacity and also makes it clear that a request for data must be made within 10 calendar days of the event. (6) Requirement R14 needs to be re-written to be consistent with the intent of the requirement as expressed in the shaded box describing the Rationale for R14. As presently written, R14 requires that the Owner must both restore recording ability AND report the inability to record data to the Regional Entity. To be consistent with the Rationale, Requirement R14 should be re-written as follows: Each Transmission Owner and Generation Owner, upon discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recording (DDR) at the bus locations as per Requirement R2 and elements as per Requirement R7, shall restore the recording ability within 90 calendar days, OR , if the recording capability cannot be restored within 90 days, report the

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

Organization	Question 7 Comment
	They are either physically isolated from one another, or connected via a normally open tie switch or breaker. In these cases, the above definition does fit this scenario and each bus should be evaluated independently. To address this scenario perhaps the definition should be re-written as follows: A single bus location includes any bus Elements at the same voltage level that are connected together within the same physical location sharing a common ground grid.

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

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

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

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

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

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

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

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

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

Organization	Question 7 Comment
Xcel Energy	(1) It appears that a lot of individual requirements are written for something that isn't overly complex. Please consider consolidating R8-R11, or consolidating the technical specs that comprise R5, R11, and R12. (2) In R14, its not clear why the Regional Entity is introduced here. Also, the Regional Entity would take on the burden of tracking corrective action plans, if the recorder isn't restored in the 90 day period. Recommend changing Regional Entity to Reliability Coordinator.
Response: (1) Each of the Requirements mentioned has its own specific reliability objective. Combining these requirements would have requirements with multiple reliability objectives which is contrary to the purpose of a requirement, and could present compliance difficulties. **(2) The requirement has been revised. If recording can't be restored within 90 calendar days, then a Corrective Action Plan has to be submitted to the Regional Entity along with a timeline for the restoration. Regional Entity is used because the Regional Entity has an overall view of the BES.**	
Entergy Services, Inc.	(1) All SER and FR data requirements should be included as part of a single table and referenced in a single requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation multiple requirements. (2) Similar to 1) above, all DDR data requirements should be included as part of a single table and referenced in a single requirement. As structured presently, if an owner fails to include or provide data for a single required element, they would be in violation of multiple requirements. (3) Add "by voltage level" in Requirement R1 so that it reads "Each Transmission Owner shall identify BES bus locations by voltage level for Sequence of Events Recording (SOER) and Fault Recording (FR)." This is consistent with Attachment 1, Step 1 and clarifies that the FR and SOER are only required at that voltage level.

Organization	Question 7 Comment
	(4) In Requirement R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the Requirement. Suggest Requirement R5.1 be reworded to say “A single record or multiple records that include at least one of the following:” (5) Reword Requirement R14 to ‘Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 upon the discovery of a failure shall: (a) Restore the recording ability within 120 calendar days; or (b) “If recording ability is not restored within 120 calendar days, demonstrate efforts to correct the unresolved failure.” Recommend increasing the allowed repair time by 30 days to allow for non-inventoried repair parts and limited access of repair personnel to such equipment which may be restricted during certain periods of the year.

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

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

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

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

Organization	Question 7 Comment
(5) The intent of Requirement R14 (now R12) was to have an entity restore recording ability within 90 days, but if that 90 day window couldn't be met then a Corrective Action Plan has to be submitted to the Regional Entity along with a timeline for the restoration. The 90 day window is realistic and practical, and compliance should not be burdensome to an entity. The wording was revised for clarification.	
El Paso Electric	(1) In respect to requirement 6.1.4, will entities be required to monitor multiple lines of a major transfer path or only one? (2) In respect to requirement 6.1.5, will one entity owning an HVDC connecting two interconnections be required to monitor both sides of the HVDC element?
Response: **(1) Referring to the response to Question 4 which was based on numerous comments received, the DMSDT has revised the draft PRC-002-2 standard, acknowledging the impact that monitoring all Elements of "major transmission interfaces" has on Transmission Owners. Sub-Parts were updated according to industry input as follows:** • **One or more BES Elements of IROLs are still included due to their significant impact on system reliability and the necessity to recreate longer-term disturbances on these key interfaces. "Major transmission interfaces" are also included but at a reduced level. Only one Element of these interfaces is required and "major" is defined by the PC or RC (according to Interconnection) based on the guidelines set forth in this standard (key major transmission interfaces to provide wide-area transmission coverage of disturbance monitoring).** **(2) Both ends of HVDC terminals have to be monitored. However, the entity is only required to monitor the end that it owns. Requirement R6 (now R5) has been revised for clarity.**	
CenterPoint Energy Houston Electric	(1) CenterPoint Energy believes the intent of some of the requirements is unclear without the corresponding Rationale box. It is our understanding that auditors may consult the rationale and other information to be placed in the Application Guidelines section; however, auditors must always refer to the requirement language. Therefore, the language of the requirements should clearly explain the intent of the requirement with less reliance on the Rationale boxes. For example;

Organization	Question 7 Comment
	Requirement R13.2 should identify the data retrieved as only the data measured within 10 days preceding a request. Recommend modifying Requirement 13.2 to read "Only recorded data measured and recorded within 10 days prior to a request will be retrievable." The Rationale box for R13 clarifies the intent of the requirement; however the language should be more specific. (2) The language for requirement R14 should explicitly identify the sub-bullets as an "or". Furthermore, CenterPoint Energy recommends modifying the second bullet of Requirement R14 to read "If the recording ability cannot be restored within 90 days, report the inability to record data to the Regional Entity along with a Corrective Action Plan (CAP) to restore the recording ability."
Response: (1) Only the language of the requirement is auditable. Rationales and guidelines are included in the standard to provide guidance to entities and auditors alike. The DMSDT has revised the wording of Part 13.2 (now Part 12.2) and provided an example in the guidelines section of the standard. (2) A list with bulleted items is an "Or" list for the bulleted items. "Or" was added between the bullets of Requirement R14 (now R12) for clarification. The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be developed. R14 (now R12) was revised to clarify.	
Public Service Enterprise Group	(1) In R2, to avoid confusion as to what the phrase "BES Elements at the locations established in Requirement R1" means, we recommend that the Attachment 1, Step 1 have this sentence modified with a new parenthetical phrase an the end: "A single bus location includes any bus Elements at the same voltage level within the same physical location sharing a common ground grid (i.e., Elements directly connected to the bus)." In addition, since the only owners of those Elements may be other TOs or GOs, the reference to "shall notify the owners of those Elements" should be clarified. This requirement should be written as follows: "Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the TRANSNISSION OWNERS AND GENERATION OWNERS of those Elements, within 90 calendar days of determination, that the Elements require Sequence of Events Recording (SOER) and Fault Recording (FR)."

Organization	Question 7 Comment
	(2) In R10, the last two bullets should be combined into one: o Under voltage trigger set at no lower than 85% of normal operating voltage for a duration of 5 seconds. (3) The language in R14 should have “either” added to clarify the required actions. In addition, the language in the second bullet “Report the inability to record data” was changed to “Report the inability to restore the recording ability.” See below. “Each Transmission Owner and Generation Owner, within 90 calendar days of the discovery of a failure of the Sequence of Events Recording (SOER), Fault Recording (FR), or Dynamic Disturbance Recoding (DDR) at the bus locations per Requirement R2 and Elements as per Requirement R7, shall EITHER: o Restore the recording ability o Report the inability to restore the recording ability to the Regional Entity along with a Corrective Action plan (CAP) to restore the recording ability.
Response: **(1) The DMSDT has combined R1 and R2(into what is now R1) to help clarify the responsibilities. Based on other commenters’ suggestions to revise Attachment 1 Step 1, the language was revised to “For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.”** **(2) The item was corrected as suggested in R10 (now R8).** **(3) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can’t be achieved then a CAP would have to be developed. R14 (now R12) was revised to clarify. The bulleted items were moved to the body of the requirement.**	
PPL NERC Registered Affiliates	(1) It appeared from the 11/19/13 webinar that the R9 obligation for GOs to “have” DDR does not mean that they must own such equipment, and this position was confirmed in the 12/5/13 NAGF outreach meeting. That is, it would do just as well to have an agreement with the TO to fulfill the PRC-002 requirements if and where the TO already has DDR on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002. R9 should have a

Organization	Question 7 Comment
	footnote saying that "This standard defines the 'what' of DDR, not the 'how.' GOs may install this equipment or, where the TO already has suitable DDR, contract with the TO." It would be still better to just eliminate GOs from the requirement, however, per our comment to question #3 above. (2) R6 sets DDR applicability criteria based on the "nameplate rating," but doesn't say of what. This could be the generator, or the most-limiting component. We believe that applicability should be based on the most-limiting component, since this sets the actual output achievable. The term, "Facility Rating," as defined in FAC-008 should then be used to avoid confusion. (3) The frequency and Hz/s settings of R10 should have a latch-time criterion, to prevent inadvertent triggering of the DME. We suggest three cycles. (4) R10 calls for DME to be triggered at no lower than 85% of normal voltage with a latch-time of 5 seconds, but the 5-second ride-through requirement of PRC-024 is only +/- 10%, which is also often where V/Hz relays are set. A trigger of 85% voltage x 5 sec may therefore cause DME to miss the action. (5) Triggered (as opposed to continuously-recording) DME needs to have sufficient storage capability to capture a major disturbance and a potentially large number of aftershocks, but we have no way of knowing how many such recordable events may occur, creating a compliance risk. The DMSDT should establish the expected maximum number of recordable events and state it in the standard.
North American Generator Forum - Standards Review Team (NAGF-SRT)	(1) It appeared from the 11/19/13 webinar that the R9 obligation for GO's to "have" DDR does not mean that they must own such equipment, and this position was confirmed in the 12/5/13 NAGF outreach meeting. That is, it would do just as well to have an agreement with the TO to fulfill the PRC-002 requirements if and where the TO already has DDR on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002. R9 should have a footnote saying that "This standard defines the 'what' of DDR, not the 'how.' GOs may install this equipment or, where the TO already has suitable DDR, contract with the TO." It would be still better to just drop GOs from the picture, however, per our

Organization	Question 7 Comment
	comment to question #3 above. Additionally, it is not clear in R9 whether the specification for signal measurements is on a per generating unit basis or if the signals of interest are a per line basis aggregate at generating stations. This determination weighs heavily on Please more clearly specify if the signals of interest are individual unit measurements or plant total measurement (grouped by output circuit, plant total, etc.). the cost and method of implementation where new equipment must be installed. (2) R6 sets DDR applicability criteria based on the "nameplate rating," but doesn't say of what. This could be the generator, or the most-limiting component. We believe that applicability should be based on the most-limiting component, since this sets the actual output achievable. The term, "Facility Rating," as defined in FAC-008 should then be used to avoid confusion. (3) The frequency and Hz/s settings of R10 should have a latch-time criterion, to prevent spurious triggering of the DME. We suggest three cycles. (4) R10 calls for DME to be triggered at no lower than 85% of normal voltage with a latch-time of 5 seconds, but the 5-second ride-through requirement of PRC-024 is only +/- 10%, which is also often where V/Hz relays are set. A trigger of 85% voltage x 5 sec may therefore cause DME to miss the action. (5) Additionally, R10 allows the use of triggered records from equipment installed prior to the effective date of PRC-002-2, but does not specify how many records an entity must be able to produce in the retrievable period specified in R13 as 10 days prior to a request. This specification is crucial to the amount of memory requirements of existing equipment. At the maximum trigger frequency (triggering every 3 minutes), the existing equipment becomes effectively a continuous recorder. For existing equipment with triggered recording capability, how many records are required to be available in the 10 day retrievable record.

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

Organization	Question 7 Comment
MVA nameplate (now Part 5.1.1). For plant/facility (now Part 5.1.1) individual generators with gross nameplate ratings greater than or equal to 300 MVA nameplate when the gross plant/facility rating is greater than or equal to 1000 MVA. **(2) Part 6.1.3 (now sub-Part 5.1.1) refers to "Generating resource(s) where:" and the sub-Parts describe the "Gross individual nameplate rating…" of those resources. Because the characteristics of the most limiting component might not affect a generator's response to system conditions, the applicability will remain based on a unit's nameplate MVA rating.** **(3) The frequency sub-Part 10.2 (now sub-part 9.2) does not preclude the use of latching or timing the trigger. The focus of this requirement is on magnitude threshold.** **(4) (5) The undervoltage trigger threshold and timer are intended to capture sustained undervoltage conditions such as fault induced delayed voltage recovery (FIDVR). The DMSDT believes these settings suffice for this purpose. Because the number of recordable events cannot be predicted, the quantity of records cannot be specified. The records of the data required by Requirement R6 (now R5) need to be retrievable for 10 days. An example has been added to the guideline section for R13 (now R11) describing the length of time data is to be retained.**	
Hydro One Networks Inc.	(1) R5.1 Bullet 2- The wording should be changed as follows: "At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder." Because the deployment of Fault Recorders are not required on every BES bus location, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it is occurring more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it. (2) R4.1- More specificity is needed in the requirement. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads - ".... Voltages for each phase of either each line or bus." which could be confusing.

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

Organization	Question 7 Comment
	(9) The way R2 is worded presently, it sounds like a TO is required to notify itself if it owns BES Elements at the bus locations. The only action in R1 is to identify busses for DME. It should probably be expanded to indicate that after the busses are identified the TO needs to have DME on the Elements that are owned by the same TO. (10) R3, R4, R12, R13, R14: List of locations that need Sequence of Events Recorders and Fault Recorders is identified in R1 and communicated in R2. Suggest replacing reference to R2 with R1 (11) R8,9,10,11 and R13, R14: Suggest changing reference to R7 with R6 (see the comment for R3 and R4 above) (12) Section 1.2 - Evidence Retention: Second sentence states:" For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit." . To avoid confusion we recommend that the DMSDT removes "may ask" and provide further clarification on what evidence needs to be retained and for how long. One approach would be to make a retention period to be "greater or longer of" the period since the last audit or the list below. (13) Section 1.2 - Evidence Retention: To avoid confusion we suggest that the retention period for R1/R2 and R6/R7 is specified as "current version of the list" or "current and previous version of the list". This will avoid confusion associated with the five years retention when the list is produced at a 5 year cycle.

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

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

Organization	Question 7 Comment

(3) The DMSDT notes that the requirement is designed to have the entity provide data and the entity has flexibility as to how this is obtained or derived. Use of Residual current and neutral current will provide similar end results.

(4) Monitoring is not required on both sides of the transformers. Derived data is acceptable. The Requirement stipulates the determination of electrical quantities. We have added a clarification to the Rationale Box: "For transformers (Part 3.2.1), the data may be from either the high side or the low side of the transformer."

(5) PRC-018-1, R6 addresses maintenance and that is not specifically required in PRC-002. The DMSDT is not prescribing a maintenance program in PRC-002 and we are only requiring that a failure of data recording is reported per Requirement R14 (now R12). Because PRC-002-2 addresses "what" data is recorded, it is intended to have PRC-018-1 retired.

(6) Because the intent of the standard is to capture BES disturbances, the R13 (now R11) applicable entities will be involved with the necessary data exchange. The standard does not prohibit individual entities from sharing data amongst themselves.

(7) Requirement R8 (now R6) and Part 8.3 (now Part 7.3) stipulate that there has to be data to determine Real and Reactive Power. The requirement is not designed to address every possible system configuration and it is recognized that there may be cases where data is not available. The measured voltage and currents will be the basis for explaining any anomalies in MW and MVAR readings.

(8) The DMSDT has combined Requirements R1 and R2 (into what is now R1), and revised the wording appropriately. The requirements have been revised to reference BES Elements consistently throughout the standard.

(9) The DMSDT has combined Requirements R1 and R2 (into what is now R1), and revised the wording appropriately.

(10) The DMSDT has combined Requirements R1 and R2 (into what is now R1), and revised the wording appropriately.

(11) Requirement R7 (R6 and R7 have been combined into R5) addresses the Responsible Entity's selection of the "final" list for DDR.

(12)The language used is the standard language required by NERC.

Organization	Question 7 Comment
(13) The DMSDT agrees and has revised the Evidence Retention section. The revision reflects the combination of Requirements R1 and R2 (into what is now R1).	
Southern Company	(1) The requirements of R3, R4, R5 and R12 for SER and FR data should be included as part of a single attachment/ table and R3 should simply reference the table. As structured presently, if an owner fails to include provide data for a single required element, they would be in violation multiple Requirements. (2) Similar to a) above, R8, R9, R10, R11, and R12 for DDR data should be included as part of a single attachment/ table or possibly separate attachments/tables for TOs and GOs and referenced in a single Requirement. As structured presently, if an owner fails to include provide data for a single required element, they would be in violation of multiple Requirements. (3) The inclusion of the word 'either' in R4.1 seems redundant. (4) R10 allows the use of triggered records from equipment installed prior to the effective date of PRC-002-2, but does not specify how many records an entity must be able to produce in the retrievable period specified in R13 as 10 days prior to a request. This specification is crucial to the amount of memory requirements of existing equipment. At the maximum trigger frequency (triggering every 3 minutes), the existing equipment becomes effectively a continuous recorder. For existing equipment with triggered recording capability, how many records are required to be available in the 10 day retrievable record?
Response: **(1) Each of the Requirements mentioned has its own specific reliability objective. Combining these requirements would have requirements with multiple reliability objectives which is contrary to the purpose of a requirement, and could present compliance difficulties. The Requirements for sequence of events recording and fault recording are sufficiently unique where there can be no violation of multiple Requirements. Note that the proposed definitions for SOER, FR, and DDR have been removed from the standard.**	

Organization	Question 7 Comment
(2) Each of the Requirements mentioned has its own specific reliability objective. Combining these requirements would have requirements with multiple reliability objectives which is contrary to the purpose of a requirement, and could present compliance difficulties. The Requirements for dynamic disturbance recording sufficiently unique where there can be no violation of multiple Requirements. **(3) The wording of Part 4.1 (now 3.1) has been revised.** **(4) Because the number of recordable events cannot be predicted, the quantity of records cannot be specified. The records of the data required by Requirement R6 (now R5) need to be retrievable for 10 calendar days. The DMSDT updated Requirement R13 (now R11) to: "Recorded data shall be retrievable for a minimum of 10 calendar days."**	
Bonneville Power Administration	(1) Introduction4. Applicability 4.1 The Responsible Entity is: BPA feels that under this section planning coordinators and reliability coordinators are named as the responsible entities which are later tasked with determining the necessary locations for dynamic disturbance recording equipment. This was one of the primary issues with the previous version of the standard, PRC-018. These entities failed to write such standards and therefore the standard lacked the necessary content for transmission and generation owners to apply. This basis will face similar challenges. Additionally this delineation of the responsible Entity takes authority away from the TOs and GOs to operate their monitoring systems in a way that makes good financial and operational sense for their individual companies. This definition should also be expanded to include Transmission Operators and Generation Operators. (2) Requirements and MeasuresR1. BPA feels the substance of this section is based on the Attachment 1, which is later labeled as Attachment A, so it is on that section that comments shall be provided. The methodology presented in Attachment 1 is overly complex and does not present a sound technical basis for the location of DFRs and SERs. Monitoring locations above 1500MVA are subject to selection based on mathematical manipulation for which no system impact basis is provided. A final step of "engineering judgment" is then applied in order to round out the list. This methodology may not result in consistent or repeatable bus selection for the placement of DFRs and SERs and will be difficult to defend in an audit scenario. This use of an MVA based location criteria is

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

Organization	Question 7 Comment
	locations which is delineated by a Responsible entity must be subject to some adjustment by the affected TO or GO. (8) R7. BPA feels the Transmission/Generation Owner/Operator must be responsible for the identification of locations which require DDRs not the Reliability Coordinator. Only in this manner may the individual TOs and GOs achieve visibility of their own systems. (9) R14. BPA feels the requirement needs to clearly indicate that it is an "OR" distinction between the two bullets. So that one-hour or one-day equipment reporting and corrective action plan is not required at the time of discovery, but rather (as is intended) only after 90 days of failure.

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

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

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

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

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

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

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

Organization	Question 7 Comment
Response: (1) Part 5.1 (now Part 4.1) was revised to include "Or". The bullets reflect the capabilities of the means of recording that are available. A list with bulleted items is an "Or" list for the bulleted items. The data specifications reflect the capabilities that exist to industry. Based on comments received 50 cycles has been reduced to 30 cycles. 2) Requirement R8 (now R6) states that the electrical quantities in the Parts can be determined which would allow the power measurements to be derived (refer to the Guideline for Requirement R8 (now R6)). 3) The DMSDT agrees and has revised the acronym throughout the standard. In the standard SER is the acronym for sequence of events recording.	
American Transmission Company, LLC	ATC recommends the following: (1) Regarding Requirement R2 - Similar to the recommendation for R1, Generator Owners, not just Transmission Owners, should be obligated to identify Elements at BES bus locations established in R1 that require SOER and FR. If any identified Elements are owned by other Generator Owners or Transmission Owners, then the Generator Owner or Transmission Owner should notify the respective owners. ATC recommends revising the R2 wording to, "Each Generator Owner and Transmission Owner shall identify which BES Elements require SOER and FR at the BES bus locations established in Requirement R1." Revise the R2.1 wording to, "Each Generator Owner and Transmission Owner shall determine whether any required Elements are owned by other Generator Owners or Transmission Owners." And finally, revise the R2.2 wording to, "If any required Elements are owned by other Generator Owners or Transmission Owners, then the Generator Owner or Transmission Owner should notify the respective owners of those Elements." (2) Regarding Requirement R3 - This requirement should follow through with the obligations that were prepared for in R2 by requiring SOER and FR for all of the Elements identified in R2, not just selected circuit breakers. ATC recommends revising the R3 wording to, "Each Generator Owner and Transmission Owner shall have SOER and FR for each Element that they own and was identified per Requirement R2."

Organization	Question 7 Comment
Response: (1) The Requirement R1 bus locations are best selected by the Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these locations. Generator Owners do not typically have the necessary case studies of the transmission system. The DMSDT has combined R1 and R2 (into what is now R1) into a single requirement and revised the wording to clarify the intent. (2) The DMSDT has designed requirements R3 (now R2) and R4 (now R3) to implement what is specified in what is now R1--only want sequence of events recording for circuit breakers and not on each Element. Fault recording data is appropriate for Elements identified in R4 (now R3). The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent.	
Reason International, Inc.	(1) Attachment 2 provides a template for standardization of Sequence of Event records. Following the successful implementation of COMTRADE and recognizing the leading role the US BES plays internationally, it would be more beneficial to all parties involved if the template was based on C37.239-2010 COMFEDE, avoiding multiple templates for SOE records in several countries.
Response: (1) The DMSDT discussed and decided on the .CSV format as being universally acceptable to industry. The .CSV format was selected to ensure uniformity in data collected.	
City of Austin dba Austin Energy	(1) City of Austin dba Austin Energy (AE) believes that the proposed PRC-002-2 standard is overly prescriptive and provides unnecessary requirements that are already addressed by Regional rules, guidelines, requirements, etc. For example, ERCOT has requirements for installing Disturbance Monitoring Equipment (DME) that may address more specific regional needs, considering ERCOT system characteristics. Additionally, AE believes the standard, as proposed, would be costly to implement.
Response: (1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:	

Organization	Question 7 Comment
"Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed. A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices." Project 2007-11 – Disturbance Monitoring was initiated to address the existing PRC-002-1 "fill in the blank" standard. FERC did not approve or remand PRC-002-1 in its Order No. 693 (March 16, 2007) because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the "fill in the blank" aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). The consolidation of these two Standards will result in a Standard that fully addresses what is necessary to capture power system disturbance data. PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data. The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events. The CEAP postings gave the opportunity to provide cost input.	
Exelon Companies	(1) Comments on R3: R3 states that circuit breaker position must be monitored for identified breakers. In our companies standard design, we connect circuit breaker auxiliary contacts to relays that include monitoring. However, this requirement will present a significant burden since a database must be created to cross-reference prints to prove that hundreds of breaker auxiliary contacts are connected to satisfy compliance requirements. Since three phase currents are to be monitored under the proposed Requirement3, this information can be used to determine circuit breaker status in lieu

Organization	Question 7 Comment
	of monitoring a 52 contact. With three phase current values available, it is not difficult to figure out when breakers were opened based on loss of current and is actually more accurate than breaker auxiliary contacts. It is very straight forward to figure out when breakers are opened based on loss of current for a straight bus configuration. If a single circuit breaker in a ring bus or similar configuration opens for some reason and flow is not interrupted the sequence of breaker openings can still be determined using currents. It is also not necessary to know exactly when a breaker in a ring bus opens if flows in the ring are merely rerouted. Thus, a detailed sequence of events timeline of a power system disturbance can be determined without the use of a circuit breaker contact. In rare cases connection of a circuit breaker contact may have been mistakenly excluded from the protection design. In this case, complying with the standard as written could require installing 1000 feet or more of control cable in an EHV switchyard, incurring a high cost for very little gain. Thus, we believe the DMSDT should eliminate this requirement as it just creates a significant burden, potentially adds cost, provides no commensurate increase in reliability, and is not necessary for events analysis when three phase currents are already required. (2) Comments on R4: It is a natural progression for a TO to upgrade BES lines before upgrading BES transformers since BES lines are subject to many more faults and operations. Thus, modernizing BES lines first has the greatest impact on reliability. For example, a large % of our comapies T-lines employ modern relays with FR and SOER capability and the remaining lines will have this capability shortly. These upgrades are being done on previously determined schedules and include all 138 kV and above lines. The percentage of BES Transformers with modern equipment is much less (15-20%) and upgrades are typically only done when transformers infrequently fail or when protective equipment is obsolete and problematic. Although R4 does state that the TO/GO shall have fault recording necessary to determine required quantities (transformer information can be determined from monitored line data as needed), the DMSDT should consider revising the guidance section of R4 to state that it is adequate to monitor lines and use their fault recordings to determine transformer quantities. The DMSDT should also consider just eliminating R4.2.1. Monitoring lines is much more important and provides information to determine flows in transformers. This would also recognize that the natural progression of system upgrades is to concentrate on the most exposed and

Organization	Question 7 Comment
	problematic areas (T-lines). The number of transformers with increased monitoring is increasing sufficiently already and monitoring of transformers inherently benefits from the rapidly increasing level of monitoring on transmission lines. (3) Comments on R5: R5.3 states that trigger settings need to include Neutral (residual) overcurrent and phase undervoltage. RFC had a disturbance monitoring standard for a few years that we worked diligently to comply with. It required triggering on one or more of various quantities including negative sequence current, negative sequence voltage, residual current, undervoltage, overvoltage, or overcurrent. ComEd met this requirement in hundreds of devices by triggering on residual current (for grd faults), phase overcurrent (for multi-phase faults), and pickup of any forward or backward (if used) phase distance zone (for multi-phase faults). Undervoltage elements weren't always available. The DMSDT should consider modifying this requirement to allow phase undervoltage or phase overcurrent as a trigger for multi-phase faults. Having to tweak hundreds of relay settings (an arduous and expensive process) to meet a NERC standard that is slightly different than the RFC standard just doesn't seem right. There is a good argument that once a system is highly monitored, triggering an event record when the relay trips provides sufficient information for events analysis. We do not believe that a standard specifying what to trigger on is necessary at all for a highly monitored system. Having to go back and change event trigger equations on a highly monitored system is purely burden to the registered entity with no commensurate increase in reliability or increased capability to analyze disturbances.

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

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

Organization	Question 7 Comment
(3) R5 (now R4): The DMSDT has revised sub-Part 5.3.2 (now sub-Part 4.3.2) to allow for overcurrent: sub-Part 5.3.2 (now sub-Part 4.3.2) reads: "Phase undervoltage or overcurrent."	
Florida Municipal Power Agency	(1) FMPA does not believe that a standard is justified for Disturbance Monitoring, as such, we believe that disturbance monitoring is better addressed through guidelines than through a standard, as further discussed below. In the scheme of things, disturbance monitoring provides very little value to operating the bulk-power system reliably as compared to other standards. Establishing SOLs and operating to them; coordinating and maintaining effective protection systems; maintaining supply/demand balance and frequency; cyber security; and effective and trained human resources are greater than one quantum step more important to reliable operations than equipment installed simply to ease the ability to perform post-mortem analyses on events and to validate stability modeling that cannot be that accurate in the first place simply due to Chaos Theory (e.g., the Butterfly Effect) and the inability to predict the future accurately. While installing DMEs may be good / prudent action, FMPA believes it is imperative to avoid a mode of thought that seems to prevail among many within our industry, and that is a mode of thought that if something is good for reliability, then we need to write a standard for it. Such mode of thought is counterproductive and stunts creative improvement because it creates a perverse incentive to only do the minimum to meet the existing standards due to the danger of better performance causing an increased level of governmental regulation. Governmental regulation should be to minimum requirements while not stunting the creativity of the industry to perform better than required, and FPA Section 215 is crafted with that thought in mind:"The term `bulk-power system' means--`(A) facilities and control systems NECESSARY FOR OPERATING an interconnected electric energy transmission network ..." (emphasis added)"The term `reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system."While DMEs may be good/prudent, they are not necessary to provide reliable operation of the bulk-power system. In addition to a lack of technical justification, a standard that requires DMEs is also not justified from a cost/benefit perspective. The benefit of DMEs as stated in the purpose of the draft standard are to assist in post-mortem analyses of events. We have been doing event analyses for decades without the standard. Yes, they may take

Organization	Question 7 Comment
	longer to perform do to the difficulty in establishing a sequence of events post-mortem and other challenges, but, we were able to do it. So, the benefit of a DME is to shorten the time and effort it takes to do a post-mortem (what is that, maybe three or four person-years, maybe a million?) compared to a cost of installing these devices and maintaining them on hundreds of buses (maybe $10's of millions) for events that may happen once in 10-20 years close enough to a DME to matter.In addition, the system has changed a lot over the last 10 years since the Northeast Blackout of 2003 and we can gain much more information now from microprocessor based relays prevalent throughout the system and phaser measurement units (PMUs) also installed throughout the system. Additionally, the effort does not justify the compliance administration costs at both the entities and at NERC and the Regions for administering compliance to this proposed standard. The standard as written is complicated, long, has many requirements, and in general is far too complicated and onerous in relation to its minimal reliability benefit. Also, how would such a proposed standard impact compliance with PRC-006, EOP-004 and other standards that require post-mortem event analyses?In conclusion, FMPA believes that a standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.

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

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

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

Organization	Question 7 Comment
applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the "fill in the blank" aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). The consolidation of these two Standards will result in a Standard that fully addresses what is necessary to capture power system disturbance data. **PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data.** **The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.**	
Nebraska Public Power District (NPPD)	(1) For clarification on R2 after receiving notification from a TO that FR or SOER may be required how long does the receiving entity have to install the appropriate recording device? Please clarify if it is still 4 years to be 100% compliant? (2) R3 can we clarify the circuit breakers that are not connected to lines and transformers designated in R4 are not required to be part of the SOER? For example, do not require SOER for a 115kV circuit breaker on a 115/34.5kV load serving transformer. (3) R4 M4 states that "Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations." For individual relays used as recorders this may encompass a significant amount of data. Consider allowing evidence to be a single design standard or common general design example to be allowed as evidence rather

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

Organization	Question 7 Comment
	voltage and current inputs 8000 samples per second, 3 dB low-pass analog filter cut-off frequency of 3000 Hz" or "protection and control processing 8 times per power system cycle". Are these examples what is asked for with 11.2? Most devices are likely to meet this rate. Does it really need to be in the standard? This seems excessive. Any options to reduce the requirements in this standard would help to limit the complexity and data to manage. (8) R13 states: "13.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request."This is a good goal to shoot far however data can be overwritten in relaying devices with the best intentions when numerous operations and voltage levels are used to trigger events. I don't feel that the ability to guarantee data is available for this time period is fully under the control of the person setting the pickup and triggering in the device 100% of the time. This should not be a finable enforceable requirement and should be removed. On occasion failing equipment can provide such great amounts of data as to overwrite memories in relaying equipment. (9) R13.4 states "Fault Recording and Dynamic Disturbance Recording data will be provided in electronic C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files." Can the statement be added that if the device is not capable of providing COMTRADE files directly then it is acceptable to provide the data in its native format? I am concerned with the need to reformat data could risk loss of data before it may ever get to an analysis team. Some formats may not be easily convertible in older devices. Consider adding: Data content requirements and guidelines shall be in accordance with R13.3, R13.4 and R13.5 or other formats deemed acceptable by the requesting regional entity. (10) R14 requires the tracking of recording failures and restoration. I recommend this only be required for recording devices not under another maintenance plan. For protective relays performing recording functions they should not be under this requirement if they are covered under PRC-005

Organization	Question 7 Comment
	which is a stringent maintenance plan that will be in place. This will reduce additional tracking requirements and burden.

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

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

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

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

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

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

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

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

Organization	Question 7 Comment
	(3) R2 and R6.2: The Implementation Plan includes specific references to time frames for becoming fully compliant with the locations lists, but the Requirement language itself does not include post-implementation compliance timelines for the required reassessments. The Implementation Plan states "Entities shall be 100% compliant with a reassessed list from Requirement R1, Part 1.2 or R6, Part 6.2 within three (3) years following notification of the list." This language should also be included in the language of the affected Requirements to prevent any disparity following the initial implementation and departure from the Implementation Plan. (4) R3: Legacy FR equipment installed before the standard effective date may not be capable of embedded SOER. R3 does not afford the same caveat for older equipment where SOER is required that R10 provides for older equipment where DDR is required. Language should be added to R3 providing the option to utilize FR digitals to monitor circuit breaker position for each circuit breaker. (5) R4 and R8: Add Rationale box stipulation that the required “electrical quantities, whether directly measured or derived,” to R4 and R8 as described below: The R4 Rationale Box explains the method of deriving electrical quantities; however, the requirement language of R4.1 does not reflect the intent described in the Rationale Box. Specifically, whether or not locations where busses are effectively tied together, such as on ring or breaker-and-half bus configurations, can derive the required phase-to-neutral voltages by monitoring a minimum of two of each phase-to-neutral voltages, from either line terminal or bus potentials. In a typical large switching station, this could eliminate costly retrofits to literally provide all three phase-neutral voltages for “each line or bus.”The language of R8.3 does not specify the method used to provide “Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.” If the intent follows the electrical quantity collection of R4, the language of R8 should also specify the ability to derive electrical quantities. Allowing calculated power flow would prevent costly retrofits to literally provide 6 dedicated analog traces for each Element required to have a DDR.

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

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

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

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

Organization	Question 7 Comment
	(8) R4.1 should be modified to state “Phase-to-neutral voltages for each phase of either each specified line or bus.” (9) In R5.1, an “or” should be added to the end of the first bullet to improve clarity. (10) Also, in R5.3 the word “settings” should be removed to improve technical accuracy. (11) In R7, the word “determination” should be replaced with “identification” to be consistent with the rest of the standard. (12) R8 should be revised as follows to improve clarity:R8.1: “At least one phase...”R8.2: “The current on the same phase as the voltage in...”R8.4: “Frequency of at least one of the.... (13) R9 should be revised as follows to improve clarity:R9.1: “At least one phase...” (14) R9.2: “The phase current on the same phase as the voltage in...”The DMSDT may want consider combining requirements that are related to the same monitoring equipment types. (15) R4 and R5 could be combined because they both relate to specifications of FR equipment. Similarly, R8, R10, and R11 could be combined, as they all relate to DDR equipment.

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

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

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

Organization	Question 7 Comment
(14) Requirement R8 (now R6) applies to the Transmission Owner; Requirement R9 (now R7) applies to the Generator Owner. Because of the differences in the requirements for each entity, those requirements will remain separate. **(15) The DMSDT does not agree with this comment. Each requirement applies to different entities and/or data requirements.**	
Wisconsin Electric Power Company	(1) In Requirement 14, there is a discrepancy between the text of R14 and the Rationale statement which follows. The bullet "Restore the recording capability" should be changed to "Restore the recording capability if possible". This will allow the entity more time if necessary to correct the problem, which is allowable as described in the Rationale. As it stands, an entity will be in violation if the recording capability is not restored within 90 days of discovery of a failure.
Response: (1) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be developed. R14 (now R12) and its Rationale Box have been revised.	
JEA	(1) It is unclear if both of the two statements in R5.5.1 are required, or if meeting only one of the two is sufficient.
Response: (1) The bullets reflect the capabilities of the means of recording that are available to industry. A list with bulleted items is an "Or" list for the bulleted items. "Or" will be added between the bullets of Part 5.1 (now 4.1) for clarification. Both bullets of 5.1 (now 4.1) are needed to address the Fault Recording that is available to industry.	

Organization	Question 7 Comment
AESI Acumen Engineered Solutions International Inc.	(1) It is understood that the intent of this version 2 of the PRC-002 Standard is to ensure that sufficient recording capability exists without being prescriptive as to the type of equipment that must be installed to meet the recording capability requirements. It is also understood that the DMSDT did not wish to be unnecessarily prescriptive with respect to periodic maintenance activities, and as such, this version 2 of PRC-002 contains no such requirement. It does not appear however that the Standard would necessarily ensure that Entities continue to have the required recording capability over time following initial installation and commissioning and after completion of the Implementation Plan. Although an Entity should be compliant at all times, is it plausible that an Entity could be unaware if some of the required recording capability is deficient or no longer exists? Disturbances do not occur very frequently, and an Entity may not become aware of deficiencies for many months or years until a disturbance occurs, when the disturbance data is requested; at which point they realize that the disturbance recording functions or capability is deficient in some manner. It could be argued that verifying compliance, and ensuring that the required recording capability exists, is the task of the auditor; however, this is dependent upon the Standard being included in an audit, and an audit itself may only occur once every 3-6 years. We suggest that the DMSDT consider adding a requirement for Entities to simply perform a periodic verification of the required recording capability, without specifying how to verify such recording capability, on an interval to be determined by the DMSDT. There are many mechanisms available for verification such as downloading recorded data, performing equipment self-tests, etc. Allowing Entities to perform periodic verification of the required recording capability in a manner they choose is consistent with the spirit of the Standard of not being unnecessarily prescriptive, and is consistent with ensuring that the required recording capability is in place.

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

Organization	Question 7 Comment
R12). It is understood that a data capture failure may only be exposed during a system disturbance, but with the extent of data capture mandated by this standard "normal" data failures can be tolerated.	
Modeling Working Group	(1) MWG finds that requirements for data retention are essential to this standard but are missing in the current draft. MWG recommends including a requirement that all triggered data recordings be retained for a minimum of 2 years and that all continuous data recordings be retained for a minimum of 30 days. MWG also recommends including a requirement that all continuous data recordings be scanned against the set of triggers defined in R10 and those portions of the continuous recordings that fall within the time periods defined by those triggers be retained for a minimum of 2 years.
Response: (1) The retention periods are specified in Requirement R13 (now R11). They were decided upon because the DMSDT felt that the data to analyze a significant system event would be called for quickly. Requesters of data also have to be aware of the retention requirements in the standard. Retention specifications beyond this "initial" data gathering are outside the scope of this standard. The DMSDT notes that this is a disturbance monitoring standard and that model verification is outside the scope of this standard.	
Dominion	(1) PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01).

Organization	Question 7 Comment
	(2) Dominion believes the intent of Requirement R2 is for Transmission Owners to notify "other" owners of BES Elements, as explained in the Rationale statement. The requirement as written would also require the Transmission Owner to notify itself. Therefore, Dominion suggests revising R2 and M2 as follows: R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the "other" owners of those Elements...M2. The Transmission Owner has dated evidence (electronic or hard copy) of notification to "other" owners of Elements... (3) In R1.2 and R 6.2, what prevents a TO or RE from assessing the locations and elements on too frequent of a time basis. As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability in where monitoring is really needed. Frequent assessments could jockey locations above and below the minimum criteria line and create confusion. (4) In R2, it infers that the TO as part of R1 developed a list of Elements, however R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest R2 be reworded to say "Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify...". If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements. (5) In R5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the requirement. We suggest R5.1 be reworded to say "A single record or multiple records that include at least one of the following:". (6) In R14, reword to indicate that the second bullet is only applicable if the first bullet is not completed within 90 days. We suggest this wording for the second bullet - "If recording ability is not restored within 90 days, report the inability..."

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

Organization	Question 7 Comment
(2) The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent. **(3) There is nothing that prevents a TO or RE from a too frequent assessment. The DMSDT does not believe that reassessment will result in a significantly different set of buses or elements for which data is required unless significant construction activity or reclassification of BES elements has occurred. If an entity is notified that they have a data obligation, the implementation plan for PRC-002 allows them three years to become compliant.** **(4) The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent.** **(5) The bullets reflect the capabilities of the means of recording that are available. A list with bulleted items is an "Or" list for the bulleted items. "Or" was added between the bullets of Requirement R5 (now R4) for clarification.** **(6) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be developed. R14 (now R12) and its Rationale Box have been revised to clarify. Requirement R14 (now R12) was revised to include "Or". The bulleted items were moved into the requirement wording.**	
New York Power Authority	(1) R10It is stated that triggered records from existing equipment can be accepted in lieu of continuous recording if the triggered records meet the criteria in 10.1 and 10.2. If continuous recording is available and meet all criteria, are triggered DDR records required? (2) R13.3There is no need to require this data to be written in CSV format. Tab delimited text would work as well and would not limit the use of commas in descriptors or other entries. The format described in Attachment 2 is limiting and incomplete (see comments on Attachment 2). (3) R13.4This requires that Fault Recording and Disturbance Recording data will be provided in COMTRADE (C37.111) formatted files, but does not specify a revision level or year for the COMTRADE standard. The requirement should specify "C37.111-2013 or later" in order to require a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.

Organization	Question 7 Comment
	(4) Attachment 2The format in Attachment 2 is limited and incomplete. While the information required is obviously necessary, the format limits or omits information available from some SOERs. R13.3 states that the files must be comma-delimited, but Attachment 2 makes no statement about the length of any string or value. There is no provision for SOERs which may have detailed descriptors of the contacts being monitored but may be a single string. “Local Time Offset from UTC” should be expressed in hours before or after UTC rather than letter designations. There is no provision for acceptable terms for “State” except for “OPEN “and “CLOSE”. Other terms may be more appropriate for some devices monitored by an SOER, such as “ENABLED” or “DISABLED”, “ON” or “OFF”, etc. In short, Attachment 2 appears to be an attempt at defining a standard but does not adequately define a format. Development of such a standard may be better left to an IEEE Working Group or other entity.
Response: (1) Triggered DDR records would not be required if continuous recording is available. **(2) The DMSDT discussed and decided on the .CSV format as being universally acceptable to industry. The .CSV format was selected to ensure uniformity in data collected.** **(3) The DMSDT agrees and has made the revision to R13 (now R11) as suggested.** **(4) The intent of Attachment 2 was to show only what would be minimally required. There is nothing to prevent the inclusion of additional data. It is not intended to have any string or value length on Attachment 2. The “Local Time Offset from UTC” column heading has been revised to reflect hours before or after UTC. The footnote for the “State” column has been revised to indicate that “OPEN” or “CLOSE” must be used for circuit breakers to be consistent with Requirement R3 (now R2), and a note added that other status monitoring indication can be used for devices other than circuit breakers.**	
Lincoln Electric System	(1) R13.2 specifies that “The recorded data will be retrievable for the period of 10 calendar days preceding a request”. As drafted, this requirement seems to indicate that if an event happened on June 1st and the data was requested on June 30th, then the data would have to be retrievable from June 20th to the 30th. However, if a request is made on June 6th following a June 1st disturbance, it would not be possible to comply with the 10 calendar day requirement.Unless LES

<table>
<tr><th>Organization</th><th>Question 7 Comment</th></tr>
<tr><td></td><td>misunderstands the DMSDT’s intent, it seems as though the requirement is meant to ensure that data is available and retrievable for a period of 10 calendar days following a disturbance in the event further analysis needs to be conducted. To ensure this intent is conveyed, LES recommends rewording R13.2 to indicate that the 10 day period starts at the time of the event. Additionally, R13.2 should also account for circumstances beyond the control of the TO or GO in which multiple events caused the relays recording the data to overwrite it with more recent events due to limited memory space. As an example, a TO could have information available for the 10 days required by the standard, but multiple disturbances due to severe weather on day 12 resulted in initial data being unavailable for a request initiated on day 12 or later. If this occurs, R13.2 would then place the Transmission Owner or Generator Owner in violation of the standard due to a limitation inherent to the relay.13.2. The recorded data will be retrievable for the period of 10 calendar days following a disturbance.(1) Footnote (1): The 10 calendar day period may be waived for circumstances beyond the control of an applicable Transmission Owner or an applicable Generator Owner, such as, but not limited to, equipment manufacturer limitations resulting in the loss of data.</td></tr>
<tr><td colspan="2">Response: (1) Requirement R13 (now R11) stipulates the expectations of a Transmission Owner after being notified data is required. Specific time frames need to be specified in the Requirement to ensure the expeditious treatment of data. Part 13.2 (now Part 12.2) has been revised to clarify the time frame for providing data. The language of Part 13.2 (now Part 12.2) has been revised to “Recorded data shall be retrievable for a minimum of 10 calendar days.” Because of the importance and need for expediency in analyzing BES system-wide disturbances, the DMSDT decided that 10 days was a reasonable time frame to have data stored for. Requesters of data will also have to be aware of the 10 calendar day requirement.</td></tr>
<tr><td>Lower Colorado River Authority</td><td>(1) R3 - clarify if EMS/RTU or Plant DCS circuit breaker timestamps will meet this requirement.
(2) R3, R4, R5, R11, R12, R13, R14 - Clarify “AND” in requirement and “OR” in measure - language is confusing. It is inconsistent.</td></tr>
</table>

Organization	Question 7 Comment
	(3) R5 - Change 5.1 minimum length from 50 to 30 cycles. An excessive number of events can cause data to be overwritten and can delay the downloading of data. (4) Change 5.3 to "Trigger settings for at least one of the following:" -OR- remove Phase undervoltage as a trigger requirement. (5) R13 - revise 13.2 from a minimum of 10 calendar days down to 5 calendar days. Longer-term storage of data may be difficult with a large number of SOER/FR/DDRs on your system. (6) R14 - change minimum response time from 90 calendar days to 180 calendar days to allow for design, procurement, and installation of long lead-time equipment/components used for SOER/FR/DDR.
LCRA Transmission Services Corporation	(1) R3 - clarify if EMS/RTU or Plant DCS circuit breaker timestamps will meet this requirement. (2) R3, R4, R5, R11, R12, R13, R14 - Clarify "AND" in requirement and "OR" in measure - language is confusing. It is inconsistent. (3) R5 - Change 5.1 minimum length from 50 to 30 cycles. An excessive number of events can cause data to be overwritten and can delay the downloading of data. (4) Change 5.3 to "Trigger settings for at least one of the following:" -OR- remove Phase undervoltage as a trigger requirement. (5) R13 - revise 13.2 from a minimum of 10 calendar days down to 5 calendar days. Longer-term storage of data may be difficult with a large number of SOER/FR/DDRs on your system. (6) R14 - change minimum response time from 90 calendar days to 180 calendar days to allow for design, procurement, and installation of long lead-time equipment/components used for SOER/FR/DDR.

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

Organization	Question 7 Comment
(2) "And" is used in the Requirements because the Requirements need to be all encompassing. The Measures are written with "Or" because they are written to address either entity's compliance with a Requirement and the types of evidence required are written as an either/or option. You do not have to have all forms of evidence. (3) In Part 5.1 (now Part 4.1) the 50 cycle requirement has been reduced to 30 cycles. (4) Both Fault Recorder Trigger settings were selected to cover those events involving and not involving ground, and those events that might not have an accompanying significant collapse in voltage. The DMSDT has revised sub-Part 5.3.2 (now 4.3.2) to revise the wording and allow for overcurrent: "4.3.2. Phase undervoltage or overcurrent." (5) The DMSDT considered the data storage necessary, and felt that the 10 days preceding a request was achievable with equipment available. (6) Based on industry comments, 90 days is realistic and practical for determining the availability of data recording capability. The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be developed. R14 (now R12) and its Rationale Box have been revised to clarify. R14 (now R12) is no longer bulleted.	
ITC	(1) R4, R11, R12, R13 and R14 need to be clear that they apply to the Element and/or equipment owner. They will be acceptable if they are reworded as:R4 after "following electrical quantities" insert "for each of the Elements they own"R11 after "for the Elements" insert "they own"R12 and R13 after "Dynamic Disturbance Recording (DDR) data for" insert "for Disturbance Monitoring Equipment they own"R14 after "or Dynamic Disturbance Recording (DDR)" insert "that they own"
Response: (1) The DMSDT has addressed ownership through revisions made to R4 (now R3), R11 (now R9), R12 (now R10), R13 (now R11) and R14 (now R12).	

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

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

Organization	Question 7 Comment
	(12) In Part 5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the requirement. We suggest R5.1 be reworded to say “A single record or multiple records that include at least one of the following:”. (13) Part 5.1 - the two bullet items in this requirement are confusing and should be reworded to clarify what is intended. (14) Part 5.1 Bullet 2- The wording should be changed as follows: “At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder.” Because the deployment of Fault Recorders are not required on every BES bus, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it is occurring more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it. (15) Part 5.2 assumes that SOE recording is driven by DFR analog sampling since it infers the achievement of a 1ms digital event resolution for a 960Hz (16x60Hz) analog sample rate. Stating analog and event resolution requirements (i.e. 16 samples per cycle and 1ms event resolution respectively) separately and explicitly is clearer and accommodates instances where SOER is separate from analog sampling. (16) Part 5.3.1. asks to have trigger settings for neutral (residual) overcurrent, which implies for R4 that it is necessary not only to determine but to monitor either each phase current or neutral current. (17) Regarding requirement R6, the standard should not create a new term like “Responsible Entity” but should only refer to specific NERC entities like TO, GO, RC, etc. (18) If the DMSDT decides to retain sub-Part 6.1.6, then it is recommended the phrase "all Elements associated with Interconnection Reliability Operating Limits" be replaced with "elements critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" similar to the language used in CIP-002-4. CIP-002-4 - Attachment 1 Critical Asset

Organization	Question 7 Comment
	Criteria reads:1.8. Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies. (19) There is an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The DMSDT has mapped this requirement to R14 of PRC-002-2. These two activities are not the same since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. R14 of PRC-002-2 requires entities to repair equipment that they know is in a failed state. (20) The Part 8.3 wording is too restrictive. Real and reactive power may not be able to be determined operationally if say a bus is split at the time of an event (or the split is caused by an event). Suggest the DMSDT correct this requirement by referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions Real and Reactive Power could be determined. The design should be assuming all normally-closed circuit breakers on a bus are closed. This avoids being out of compliance during a specific event, if open bus breakers preclude recording the MVA flows on all elements. (21) Requirement R10 should allow the legacy equipment to have multiple triggered records which make up the required length. It is stated that triggered records from existing equipment can be accepted in lieu of continuous recording if the triggered records meet the criteria in 10.1 and 10.2. If continuous recording is available and meet all criteria, are triggered DDR records required? (22) R13 - this requirement places the RC, RE and/or NERC in the middle of data sharing. There is no requirement in the standard to facilitate entities to partake in data sharing. Is this really the intent? What if adjacent entities need to exchange post-disturbance information? Does that really need to occur via the RC, RE or NERC if an entity cannot directly request necessary data? (23) Requirement R13, Part 13.3. asks for SOER data in Comma Separated Value (.CSV) format whereas the majority of Disturbance Monitoring Equipment (DME) do not save data in this

Organization	Question 7 Comment
	format. In addition, if breaker open/close position determination from FR data is acceptable, no .CSV file can be created by the recording tool itself. There is no need to require this data to be written in CSV format. Tab delimited text would work as well and would not limit the use of commas in descriptors or other entries. (24) The format described in Attachment 2 is limiting and incomplete (see comments on Attachment 2 below). (25) Similarly, R13 Part 13.4. asks for FR and DDR data in C37.111 , IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files whereas the majority of DME equipment does not save data in this format. Are manually converted records acceptable? This requires that Fault Recording and Disturbance Recording data will be provided in COMTRADE (C37.111) formatted files, but does not specify a revision level or year for the COMTRADE standard. The requirement should specify “C37.111-2013 or later” in order to require a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data. (26) In R14, reword to indicate that the second bullet is only applicable if the first bullet is not completed within 90 days. We suggest this wording for the second bullet - “If recording ability is not restored within 90 days, report the inability...” The Rationale for requirement R14 recognizes that the DME equipment cannot be always returned to service within 90 calendar days of the discovery of a failure. Requirement R14 itself, however, is not clear and should be rewritten to reflect that. (27) PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements.

Organization	Question 7 Comment
	(28) Regarding Attachment 2, the format in Attachment 2 is limited and incomplete. While the information required is obviously necessary, the format limits or omits information available from some SOERs. R13.3 states that the files must be comma-delimited, but Attachment 2 makes no statement about the length of any string or value. There is no provision for SOERs which may have detailed descriptors of the contacts being monitored but may be a single string. "Local Time Offset from UTC" should be expressed in hours before or after UTC rather than letter designations. There is no provision for acceptable terms for "State" except for "OPEN "and "CLOSE". Other terms may be more appropriate for some devices monitored by an SOER, such as "ENABLED" or "DISABLED", "ON" or "OFF", etc. In short, Attachment 2 appears to be an attempt at defining a standard but does not adequately define a format. Development of such a standard may be better left to an IEEE Working Group or other entity.

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

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

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

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

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

Organization	Question 7 Comment
Requirement stipulates the determination of electrical quantities. We have added a clarification to the Rationale Box: "For transformers ((now)Part 3.2.1), the data may be from either the high side or the low side of the transformer." (8) The standard offers two option; either bus or line voltages. For each phase, you can use a bus or a line. The intent of the Requirement is to lay the foundation for capturing adequate data for event analysis. Bus voltages could be used in lieu of each of the Elements connected to that bus. (9) For the purposes of FR data, residual and neutral currents are the same. The DMSDT noted that the requirement is designed to have the entity provide data and the entity has flexibility as to how this is obtained or derived. Use of residual current or neutral current will provide the same results. They represent the zero sequence component of the fault current and are measured/determined by different techniques. (10) Monitoring is not required on both sides of the transformers. Derived data is acceptable. The Requirement stipulates the determination of electrical quantities. A clarification has been added to the Rationale Box: "For transformers (now Part 3.2.1), the data may be from either the high side or the low side of the transformer." (11) The DMSDT reviewed M4 (now M3) and found that the words "plus evidence the device was commissioned to capture data at the specific bus in question" did not need to be added because commissioning is not necessary for the acquisition of appropriate data.(12) A list with bulleted items is an "Or" list for the bulleted items. "Or" was added between the bullets of now Part 4.1 for clarification. (13) The DMSDT has revised the bullets for clarity: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 30 cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder. (14) The standard refers to data and not equipment. See the preceding response. (15) Part 5.2 (now Part 4.2) only applies to FR and there is no linkage to SER. The specifics of sequence of event and fault recording data are separate and succinct.	

Organization	Question 7 Comment
(16) The DMSDT agrees that the triggering specified in Part 5.3.1 (now Part 4.3.1) requires monitoring either all phase currents or neutral current. (17) Because of the different responsibilities of entities throughout the continent, the DMSDT decided that the use of Responsible Entity was most appropriate. Responsible Entity is not a new term and is used in other NERC standards. (18) The wording of Part 6.1.6 (now sub-Part 5.1.4) has been revised to "One or more BES Elements associated with each Interconnection Reliability Operating Limit (IROL)." (19) PRC-002 addresses the provision of data. It does not address equipment nor does it address maintenance of equipment. PRC-018-1, R6 addresses maintenance and that is not specifically required in PRC-002-2. The DMSDT is not prescribing a maintenance program in PRC-002-2 and is only requiring that a failure of data recording is corrected according to R14 (now R12). The Notes Section on p. 13 of the Mapping Document explains the rationale behind mapping PRC-018-1 Requirement R6 to PRC-002-2 Requirement R14 (now R12). From the Mapping Document: "PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R14 (now R12) deals with the long term availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability." The Mapping Document was revised to reflect the R14 (now R12) wording. (20) The DMSDT has added verbiage to the Guidelines section of the standard to indicate this: "The data requirements for PRC-002-2 are based on a system configuration assuming all normally closed circuit breakers on a bus are closed." (21) As stated in Requirement R10 (now R8), if there isn't continuous data recording on already installed equipment, Parts 10.1 (now Part 9.1) and 10.2 (now Part 9.2) must be met. If continuous recording is available for Elements, then the triggered recording is not required for those Elements. (22) Entities can share data with whomever they deem necessary as it is not precluded in the standard. This Requirement ensures that the RC, or NERC get the data because the intent of PRC-002-2 is to ensure that there is data available to analyze	

Organization	Question 7 Comment
wide-area disturbances. This Requirement does not state that data has to go through the RC, RE, or NERC. The dictates for sharing data are outside the scope of this standard. **(23) The DMSDT discussed and decided on the .CSV format as being universally acceptable to industry. The .CSV format was selected to ensure uniformity in data collected.** **(24)(25) The DMSDT has added language to clarify Part 13.4 (now 12.4) to indicate the version of C37.111 should be C37.111-2013 or later.** **(26) The intent of Requirement R14 (now R12) is to have recording failures restored within 90 days of discovery, and if that can't be achieved then a CAP would have to be developed. R14 (now R12) and its Rationale Box were revised to clarify.** **(27) The DMSDT is aware of NPCC's PRC-002-NPCC-01, and that its DMSDT has been reconvened to review the Regional Standard with respect to PRC-002-2 after it is approved. There won't be a variance for the NPCC Standard, because after review if requirements in PRC-002-NPCC-01 were more stringent than PRC-002-2 they would be kept.** **(28) The intent of Attachment 2 was to only show what would be minimally required. There is nothing to prevent the inclusion of additional data. It is not intended to have any string or value length on Attachment 2. The "Local Time Offset from UTC" column heading has been revised to reflect hours before or after UTC. The footnote for the "State" column has been revised to indicate that "OPEN" or "CLOSE" must be used for circuit breakers to be consistent with Requirement R3 (now R2), and a note added that other status monitoring indication wording can be used for devices other than circuit breakers.**	
Dynegy	(1) Regional Standard PRC-002-NPCC-01 technical specifications for DDR conflict with PRC-002-2 technical specifications. The NPCC Regional Standard R9 specifies a DDR recording rate of 6 times per second while PRC-002-2 specifies 30 times per second. Conflicts with the Regional Standard should be removed so entities are not penalized for Regional Standard compliance.
Response: (1) As explained in the Guidelines for Requirement R11 (now R9), the 30 times per second output recording rate is necessary to capture certain dynamic events. If the NERC standard is met, NPCC requirements will be exceeded.	

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

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

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

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

(3) The DMSDT has made the suggested revision.

Organization	Question 7 Comment
(4) The DMSDT has made the revision. **(5) The DMSDT made the necessary wording and grammatical revisions to the standard. Wide-area has been hyphenated in the standard. The Rationale Boxes stay with the standard after it is approved. They get moved to the end of the standard.**	
Luminant Generation Company LLC	(1) Requirement R4 as written could require both the Transmission Owner and the Generator Owner to monitor the requested electrical quantities for all lines and elements at the bus or switchyard where the generator is interconnected. R4 needs to be re-written to clarify that the GO is only responsible for monitoring for faults on the equipment it owns and the same for the TO. (2) For Requirement R13, subsections 13.3, 13.4 and 13.5 should be deleted from the standard entirely. These items are completely administrative in nature and are not results based. An entity could make a typo mistake in formatting or when naming a file and be non-compliant with the requirement. Also, the sub-requirements reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. (3) Finally, the standard is written in a confusing format where twelve of the 14 requirements in the standard reference other requirements, which in many cases reference another requirement (or two). As a GO, I need to know, in a clear concise manner, what electrical quantities or status I need to monitor where, and what attributes are needed for the disturbance monitoring equipment
Response: (1) The wording of Requirement R4 (now R3) has been revised. "Each Transmission Owner and Generator Owner shall have the following FR data to determine the following electrical quantities for each of the BES Elements they own connected to the BES buses identified in Requirement R1:"	

Organization	Question 7 Comment
(2) The need for the items in Parts 13.3 (now Part 12.3), 13.4 (now Part 12.4), and 13.5 (now Part 12.5) were made necessary due to problems with formatting of the submitted data after the 2003 Blackout. Data submitted was in different formats, making a difficult task that much harder. Because of the necessity to have data in the right formats, Parts 13.4 (now 12.4) and 13.5 (now 12.5) are needed. **(3) Making references between requirements in the standard was necessary to avoid repetition and wording. Requirements referencing other requirements simplify the measures. Requirements R1 and R2 have been combined (into what is now R1) which reduced the number of requirements referencing other requirements.**	
ReliabilityFirst	(1) Requirement R4, Part 4.2.1 - With the forthcoming approval of the NERC BES Definition including "Transformers with the primary terminal and at least one secondary terminal operated at 100 kV...", ReliabilityFirst does not believe the informative language in Requirement R4, Part 4.2.1 is needed and recommends removing the following language from Requirement R4, Part 4.2.1: "that have a low-side operating voltage of 100kV or above" since it serves no purpose. (2) Requirement R14 - ReliabilityFirst does not believe there is any value for an Entity to report their inability to record data (due to a failure of a FR, SOER or DDR) to the Regional Entity. ReliabilityFirst believes the record keeping will be burdensome with little or no benefit. ReliabilityFirst would rather like to see the Entities get the corrective actions plans in place and the equipment fixed, thus the Regions really have no need for this type of report. Compliance can be monitored through a data submittal on an annual basis rather than an ongoing reporting requirement. Also, even though a bulleted list in a Reliability Standard indicates an "or" statement, it is still unclear that these are considered two options. ReliabilityFirst recommends adding the word "either" after the word "shall" in the parent Requirement R14 and including the word "or" after the word "ability" in the first bullet. ReliabilityFirst also recommends the following to remove the Regional Entity from the second bullet and adding a time frame for when the CAP needs to be completed (it should not be open ended): "Develop and implement a Corrective Action Plan (CAP) to restore the recording ability within xx days."

<table>
<tr><th>Organization</th><th>Question 7 Comment</th></tr>
<tr><td></td><td>Also, the CAP should not have an open-ended time frame for completion, such as years into the future. There needs to be some time limit for correction.</td></tr>
<tr><td colspan="2">Response: (1) The DMSDT has retained the language to emphasize different transmission levels. This requirement excludes GSU transformers.

(2) Oversight is needed for the availability of Disturbance monitoring recording capability, and in the revised R14 (now R12) wording the DMSDT stipulates the submission of a Corrective Action Plan to the Regional Entity. The DMSDT has also added language to R14 (now R12) that requires the entity to include a timeline for restoration of data recording ability within the CAP.</td></tr>
<tr><td>ISO New England Inc.</td><td>(1) Requirement R5.1 currently reads:5.1. A single record or multiple records that include: o A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. o At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault.Comment R5.1 - the two bullet items in this requirement are confusing/conflicting and should be reworded to clarify what is intended. I.E. is it 50 cycles per bullet 1 or three cycles per bullet 2? This is probably for single and multiple records but the language should identify the difference as shown below. o A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point. (Single Record Only) o At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault. (Multiple Records Only)
(2) Comment on R13, this requirement could place the Reliability Coordinator/Planning Coordinator in the middle of data sharing. This requirement should encourage direct sharing of data.
(3) Also, R13.3 and Attachment 2 attempts to define yet another format for SOE data; There are well established formats for this type of data, such as COMTRADE, that include many other aspects of data such as file and signal naming conventions.</td></tr>
</table>

Organization	Question 7 Comment
Response: (1) "Or" was added between the bullets of Part 5.1 (now 4.1) for clarification. Both bullets of 5.1 (now 4.1) are needed to address the Fault Recording capability that is available to industry. The DMSDT has changed 50 cycles to 30 cycles in the first bullet. The bullets, as stated in the standard, apply to single or multiple records. (2) Entities can share data with whomever they deem necessary as it is not precluded in the standard. This requirement ensures that the RC, Regional Entity, and NERC get the data because the intent of PRC-002-2 is to ensure that there is data available to analyze wide-area disturbances. This requirement does not state that data has to go through the RC, RE, or NERC. The dictates for sharing data are outside the scope of this standard. (3) The DMSDT discussed and decided on the .CSV format as being universally acceptable to industry. The .CSV format was selected to ensure uniformity in data collected. COMTRADE is for transient data reporting and binary data associated with it.	
Seattle City Light	(1) Seattle City Light appreciates the effort of the DMSDT in developing this proposed Standand, and understand the concept to focus requirement on data requirements rather than equipment requirements. That said, Seattle does not support this draft or approach. The draft is far too complex and technical to be an effective Federal regulation, in part because it requires a slow and cubmersome process to update each time a technical specification goes out of date. Seattle recommends that the Standard be revised to provide general requirements that are consistent over time, with details referenced in a separate document similar to the data collection and data preparation manuals associated with data-collection regulations in other areas (such as for regional model development). Additionally, Seattle cannot support such a detailed and complex Standard until additional guidance is available about the compliance implications, such as an RSAW or guidance document.
Response: (1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report: "Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.	

Organization	Question 7 Comment

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

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

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

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

Organization	Question 7 Comment
Western Area Power Administration	(1) Section 5.3 - Disagree with the trigger requirements as written. There are many factors that contribute to effective triggering such as: o Triggering for local vs. remote faults o Avoiding over-triggering that could result in "information overload" and the filling up of data storage o Capturing relevant and complete fault representationThe requirements stated are inadequate. It is felt that trigger settings are best left to the professional judgement of the relay engineer. While triggering on Neutral (residual) overcurrent is often standard, care must be taken regarding the sensitivity level. Similarly, triggering issues related to sensitivity and pickup time are associated with phase undervoltage triggering. Other triggering methods (such as based on protection element pickup) may be preferred instead of undervoltage methods. (2) Section R13 - the requirements of R13.4 and R13.5, while achievable, are somewhat archaic. More flexibility should be allowed for frequently used, industry standardized fault recording formats such as SEL event records. Also, the naming convention put forth in C37.232 is not the easiest to follow.
Response: (1) Triggering setting values are not specified in Part 5.3 (now Part 4.3), just the quantities to be used as triggers. Additional triggers may be set based on professional judgment. **(2) The formats listed were established from knowing what is available to and being used by industry**.	
Liberty Electric Power LLC	See NAGF SRT comments.
Response: Please see the DMSDT response to the NAGF SRT comments.	
Colorado Springs Utilities	(1) Thank you standard DMSDT for all of your efforts. We believe that all of the disturbance monitoring equipment referenced in this standard can be very helpful to an organization. We do not believe that it has a reliability impact that merits the cost in time and money to install, maintain, and report on all these devices as specified in the standard. As shown by the VRFs this does not highly impact reliability and although disturbance monitoring is something that

Organization	Question 7 Comment
	could be useful, at times, should not be part of a mandatory standard. If a standard is to be implemented, we view the approach as written, to be too broad and cumbersome. We would recommend that a technical criteria based on system configuration be established to identify critical points for disturbance monitoring (DM) and that DM be implemented at those locations. We believe a more focused and technically based approach to placement of DM equipment would yield higher benefits while eliminating unnecessary and undesirable impacts.

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

"Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.
A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices."
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PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that might arise from the technological advances being made to record the data.

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

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

Organization	Question 7 Comment

Response: (1) The DMSDT has combined R1 and R2 into a single requirement (into what is now R1) and revised the wording to clarify the intent.

(2) The requirement has been revised to specify the determination of each phase of each specified BES bus. The intent of the Requirement is to lay the foundation for capturing adequate data for event analysis

(3) For the purposes of FR data, residual and neutral currents are the same. The DMSDT noted that the requirement is designed to have the entity provide data and the entity has flexibility as to how this is obtained or derived. Use of residual current or neutral current will provide the same results. They represent the zero sequence component of the fault current and are measured/determined by different techniques.

(4) Monitoring is not required on both sides of the transformers. Derived data is acceptable. The Requirement stipulates the determination of electrical quantities. A clarification has been added to the Rationale Box: "For transformers (now Part 3.2.1), the data may be from either the high side or the low side of the transformer."

(5) The standard refers to data and not equipment. The DMSDT has revised the bullets for clarity:

- **A pre-trigger record length of at least two cycles and a post-trigger record length of at least 30 cycles for the same trigger point, or**
- **At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.**

(6) PRC-002 addresses the provision of data. It does not address equipment nor does it address maintenance of equipment. PRC-018-1, R6 addresses maintenance and that is not specifically required in PRC-002-2. The DMSDT is not prescribing a maintenance program in PRC-002-2 and is only requiring that a failure of data recording is corrected according to R14 (now R12). The Notes Section on p. 13 of the Mapping Document explains the rationale behind mapping PRC-018-1 Requirement R6 to PRC-002-2 Requirement R14 (now R12). From the Mapping Document: "PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R14 (now R12) deals with the long term

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

Organization	Question 7 Comment
Response: (1) It is intended that this standard ensure the capture of adequate data to analyze major system disturbances, and the wording reflects that intention. The standard addresses not "how" the data is captured, but "what" data is captured.	
Arizona Public Service Company	The proposed standard still needs work before it is acceptable. The following items need to be addressed: (1) The standard requires all owners of identified BES elements to implement the various types of recording. However, for jointly owned facilities, this puts co-owners in a position whereby they can be held in violation of the standard if the operating/maintenance entity of a co-owned facility does not implement and maintain compliance with the standard. For jointly owned facilities, the standard should specifically address which of the co-owners (preferably the co-owner that operates or maintains the facility) is responsible for compliance with the standard. (2) Requirement 14 needs to be re-written. As it is now written, R14 requires that a TO or GO formally report to the Regional Entity an outage of any of the recording capabilities covered by the standard along with a Corrective Action Plan. However, in the "Rationale for R14" discussion that is included it is clear that the intent or this requirement is to require the TO/GO to report the problem only if they cannot restore the lost recording capability within 90 days. The requirement needs to be re-written to state the actual intent because as it is now written, one must contact the Regional entity every time the recording capability goes out, no matter how long it went out for. (3) Requirements R10 through R13 all seem to be required specifications and shouldn't have their own requirements but could rather be combined into an Appendix to the standard. (4) The standard should allow for monitoring/recording up to the capability of the equipment presently installed (this is not referring to the capability of the presently installed recording capability but rather the presently installed BES equipment capability). A utility shouldn't have to install major

Organization	Question 7 Comment
	equipment (CCVTs, breakers, etc) just to meet the standard if their presently installed equipment doesn't allow adequate monitoring. (5) In Requirement R3 it is not clear if a GO will be required to monitor a low side generator breaker. The standard refers to breaker connected to the identified bus location. If this refers to each breaker that is directly connected to the bus location, the requirement should use the term "directly". Without qualifying as such, the question remains as to whether the low side breaker qualified as being connected to the bus since it is connected to the bus through the GSU transformer.
Response: (1) The registered owner that is responsible for compliance with NERC standards would be the one responsible for this standard as well. **(2) The wording of Requirement R14 (now R12) and its Rationale Box has been revised for clarification. See the Rationale Box for an explanation of the intent of this requirement**. **(3) The DMSDT considered combining Requirements R10 through R13, but decided that it was simpler and created a less cumbersome standard to leave them as separate requirements.** **(4) The requirements allow for flexibility in how the data is captured. Requirement R4 (now R3) requires entities to be able to determine electrical quantities, not actually have to measure them.** **(5) Requirement R3 (now R2) only relates to BES Elements determined by the Transmission Owner in Requirement R1. These Elements are connected to the TO's BES buses and do not include generator transformer low side breakers.**	
Tacoma Power	(1) There is general concern about the cost of implementation, especially cost sharing for installation of Dynamic Disturbance Recording (DDR). For example, the Responsible Entity seems to have latitude on selecting BES Elements, beyond the DDR locations identified in Requirement R6, Parts 6.1.3 through 6.1.7, and therefore which Transmission Owners and Generator Owners must install DDR to meet Requirement R6, Part 6.1.1. (2) If two Transmission Owners share equipment at a BES bus location, which Transmission Owner is responsible under R1 and R2 for identification and notification?

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

Organization	Question 7 Comment
	(11) Under Requirement R14, does loss of time synchronization qualify as a "failure"? Generally, it seems that this type of issue would be corrected quickly (within 90 calendar days of discovery) and therefore not require reporting. (12) Under Requirement R14, if a Transmission Owner or Generator Owner restores the recording ability within 90 calendar days of the discovery of a failure, does the failure need to be reported to the Regional Entity to be compliant with Requirement R14? In other words, do the bulleted items under Requirement R14 constitute an 'and' or 'or' condition? (13) In Attachment 1, Step 1, would bus Elements on the high-side of transformation at the same physical location be considered a single bus location and be distinct from the bus Elements on the low-side of the transformation, even if both sets of bus Elements share a common ground grid? In other words, is it possible to have two bus locations at the same physical location, even if they share a common ground grid, provided that there is transformation connecting the two bus locations? Consider a 230kV to 115kV substation. (14) In Attachment 1, Step 1, what is meant by the verbiage "...or from other DME devices"? Additionally, the acronym 'DME' does not appear to be defined in the standard itself (only in the Rationale for R14).

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

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

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

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

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

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

Organization	Question 7 Comment
	provide data for a single required element, they would be in violation of multiple Requirements. (3) Provide at least one example in the Guidance Section, or develop a reference document similar to the BES Definition effort. A system one line similar to BES Definition Reference Figure S1-1 augmented with circuit breakers in various configurations (e.g. straight bus, ring bus, breaker-and-a-half). The DMSDT could go through the various Requirements to demonstrate the DMSDT intentions. Although the present guidance and rationale are helpful, we believe there are still many unclear aspects to these Requirements. (4) Add 'by voltage level' in Requirement R1 so that it reads 'Each Transmission Owner shall identify BES bus locations by voltage level for Sequence of Events Recording (SOER) and Fault Recording (FR).' This is consistent with Attachment 1, Step 1 and clarifies that the FR and SOER are only required at that voltage level. (5) In Requirements R1.2 and R 6.2, what prevents a TO or RE from assessing the locations and elements on too frequent of a time basis? As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability in where monitoring is really needed. Frequent assessments could jockey locations above and below the minimum criteria line and create confusion. (6) In Requirement R2, it infers that the TO as part of Requirement R1 develop a list of Elements;, however, Requirement R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest Requirement R2 be reworded to say "Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify...". If it was the intent that the GOs (and other affected TOs)

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

Organization	Question 7 Comment
	of data and can act as a clearinghouse if indeed the Reliability Coordinator and/or NERC need the exact same data. The reality is that all these entities will collaborate in the disturbance analysis if an event of this magnitude ever does occur. It is unreasonable to require the TO and GO to respond to duplicative data requests in such a short time. (12) Reword Requirement R14 to 'Each Transmission Owner and Generator Owner that is responsible for Sequence of Events Recording (SOER) and Fault Recording (FR) at the bus locations on BES Elements as per Requirement R2, and Dynamic Disturbance Recording (DDR) on BES Elements as per Requirement R7 upon the discovery of a failure shall: (a) Restore the recording ability within 120 calendar days; or (b) If recording ability is not restored within 120 calendar days, demonstrate efforts to correct the unresolved failure.' Please increase the allowed repair time by 30 days because the access of repair personnel to such equipment is often restricted during certain periods of the year. In addition; revise the second part to be consistent with the handling of Unresolved Maintenance Issues in PRC-005-2 R5. This change triggers an M14 part (3) change to "(3) if not repaired within 120 calendar days of discovery, evidence that it has undertaken efforts to correct the unresolved failure Issues in accordance with Requirement R14. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.' We believe that the proposed reporting requirement is much too burdensome for this equipment.

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

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

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

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

Additional Comments:

PEPCO

David Thorne

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

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

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

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

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

6. Do you agree with the Implementation Plan? If not, please explain why.
No
Question 6 Comments:
1) Implementation for Requirement R14, as presently written, applies 9 months after the standard is approved. This requirement needs to be clarified. It should only apply to those SOE, FR, and DDR devices that have been installed in accordance with, and meet the requirements of, this standard. Legacy DME equipment that may exist at one of the busses identified in R1, which does not meet the requirements of this standard, should not be subject to Requirement R14, until the equipment is upgraded, or replaced, to meet the full requirements of this standard. This clarification needs to be made, or, the implementation for R14 should be moved to coincide with the timetable for Requirements R3, R4, R5, R8, R9, R10, R11, R12 and R13.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PSE

Karen Silverman

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

Yes

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

No

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

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

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

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

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

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

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

No

Question 6 Comments:

Referring to comments to Question 2, it would be prudent to at first require a subset of the Fault Recording, SOER and DDR to be up and running and monitored for 2-3 years. Then NERC, WECC and entities can refine the standard based upon what we learn. In a nutshell, we should start small.

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

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

Question 7 Comments:

While Entities, especially some of the larger Entities, may have a lot of FR, SOER and DDR equipment already in place, the level of capability of some of the equipment may need to be upgraded. This will take time and money.

<u>Response</u>: Recommend participation in the CEAP for this project.

DTE

Kathleen Black

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

Yes

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

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

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

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

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

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

END OF REPORT

Standard Development Timeline

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

Development Steps Completed

1. Nominations for the SAR Drafting Team members were solicited February 26 – March 9, 2007.
2. The SAR was posted for a 30-day comment period March 22 – April 20, 2007.
3. Nominations for the Disturbance Monitoring Standard Drafting Team (DMSDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.
4. The project was placed into informal development the fall of 2010.
5. The project was placed into formal development January 2013.
6. Nominations for two additional DMSDT members were solicited April 12 – 25, 2013.
7. Three additional DMSDT members were added May 22, 2013.
8. Industry webinar was held May 22, 2013.
9. Industry technical conferences were held July 30 - 31, 2013 and August 6 - 7, 2013.
10. The draft standard was posted for a 45-day concurrent comment and ballot period November 1 – December 16, 2013.

Description of Current Draft

This is the second draft of the proposed standard and is being posted for stakeholder comments and additional ballot. This draft includes the modifications based on comments submitted by stakeholders

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with a 10-day Ballot	May 2014
Final Ballot	July 2014
BOT Adoption	August 2014

Effective Dates

The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan.

Implementation Plan for PRC-002-2 Requirements R1 and R5:

Entities shall be 100% compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirement R12:

Entities shall be 100% compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:

- Entities shall be at least 50% compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date.

- Entities that own only one (1) identified BES bus location, Element, or generating unit shall be fully compliant within four (4) years of the Effective Date.

- Note: Entities that own only one (1) identified BES bus, BES Element, or generating unit and are notified by an entity shall be 100% compliant within six (6) years following notification.

Entities shall be 100% compliant with a reassessed list from Requirement R1or R5 within three (3) years following notification of the list.

Version History

Version	Date	Action	Change Tracking
2.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms (Glossary) used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

When this standard has received ballot approval, the Rationale Boxes will be moved to the Guidelines and Technical Basis Section of the Standard.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.
4. **Applicability:**

Functional Entities:

4.1 The Responsible Entity is:

4.1.1 Eastern Interconnection – Planning Coordinator

4.1.2 ERCOT – Planning Coordinator or Reliability Coordinator

4.1.3 Western Interconnection – Reliability Coordinator

4.2 Transmission Owner

4.3 Generator Owner

Rationale for Functional Entities:

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

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

B. Requirements and Measures

R1. Each Transmission Owner shall identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days that those BES Elements may require SER data and/or FR data, and reevaluate the identified BES buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data are required, identified in accordance with Attachment 1, and evidence that the bus identification has been reevaluated within the required interval. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Requirement R1 directs a uniform methodology to identify these BES buses. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of transmission lines and other Elements connected to the bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on system reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause large cascading system events, so SER and FR data from these BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment. Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection.

For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data are required, based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and system topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data are required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. SER and FR data will include generating resource contributions to an event. DDR data better shows generator response to disturbances.

Each Transmission Owner must reevaluate the list of BES buses every five calendar years to address system changes.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90 calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

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

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which can include a single design standard as representative for common installations; or (2) actual data recordings.

Rationale for R2:

The intent is to capture SER data (opening/closing) for the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance. Other status monitoring indications can be used for devices other than circuit breakers.

R3. Each Transmission Owner and Generator Owner shall have the following FR data to determine the following electrical quantities for each of the BES Elements they own connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltages for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations including a single design standard as a representation for common installations; or (2) actual data recordings or derivations.

Rationale for R3:

The required electrical quantities may either be directly measured or derivable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for system disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a post-trigger record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) device specification (R4, Part 4.2) and configuration (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power system operations and determination if operations were as designed. System faults generally persist for a short time period, thus, a 30 cycle post-trigger minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30 contiguous cycles post-trigger.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

R5. Each Responsible Entity shall identify BES Elements for which dynamic disturbance recording (DDR) data is required, notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 The BES Elements shall include the following:

5.1.1 Generating resource(s) with:

- Gross individual nameplate rating greater than or equal to 500 MVA, or
- Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

5.1.2 Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines:

- Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection, or
- Transfer Paths in the Western Interconnection Path Rating Catalog, or
- Voltage stability limited transfer paths or load serving area, or
- Interfaces between Balancing Authority Areas, or
- Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements associated with Interconnection Reliability Operating Limits (IROLs).

5.1.5 Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.

5.2 The BES Elements shall include a minimum of:

5.2.1 One BES Element.

5.2.2 One additional BES Element for each additional 3,000 MW of its historical peak system Demand.

M5. The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for DDR data, identified in accordance with Requirement R5, assessed within the required interval, dated evidence (electronic or hard copy) of notification to each Transmission Owner or Generator Owner of Elements identified in Requirement R5. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R5:

DDR plays a crucial role in wide-area disturbance analysis, and the Responsible Entity needs to ensure that there are sufficient BES Elements identified for DDR data capture. Additionally, DDR is used for capturing the Bulk Electric System transient and post-transient response and for validating the system performance. The requirement for DDR data for identified BES Elements, for the purpose of this standard, is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-assessment of the list is a reasonable interval for this review.

The DDR data is to be captured for a BES Element, and with the exception of HVDC, is obtainable from one terminal of an Element. This pertains to “major transmission interfaces”.

For HVDC (Part 5.1.3), each Transmission Owner is only responsible for DDR data for the Elements that it owns.

Part 5.1.5 is intended to have DDR data for at least one BES Element in a portion of the BES with a voltage response for system events that has required the installation of a UVLS.

It is intended that a Responsible Entity will have DDR data for one BES Element and one additional BES Element for each 3,000 MW of its historical peak system Demand.

Communication of selected Elements is required to ensure that the owners of the respective Elements are aware of their responsibilities under this standard. The Responsible Entity is only required to share the list of required Elements that each Transmission Owner and Generator Owner owns.

R6. Each Transmission Owner shall have DDR data for each BES Element it owns for which it received notification as identified in Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

Rationale for R6:

Dynamic disturbance recording is used for measurement of transient response to system disturbances, during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the buses within a location are at the same frequency one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a system configuration assuming all normally closed circuit breakers on a bus are closed.

R7. Each Generator Owner shall have DDR data for each BES Element it owns and is notified according to Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step up (GSU) transformer high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

Rationale for R7:

A crucial part of wide-area disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high or low-side of the generator step up (GSU) transformer, measuring the specified electrical quantities, to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how.' Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

R8. Each Transmission Owner and Generator Owner responsible for DDR data in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recording and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings.

Rationale for R8:

Large scale system outages generally are an evolving sequence of events that occur over an extended period of time, making DDR essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

R9. Each Transmission Owner and Generator Owner in Requirement R5 shall have DDR data that conforms to the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings (R9, Part 9.2).

Rationale for R9:

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle, on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power system disturbances.

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER, FR and DDR data for the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 to within ± 2 milliseconds of Coordinated Universal Time (UTC), time stamped with or without a local time offset. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings, or (3) station drawings.

Rationale for R10:

Time synchronization of disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of ±2 milliseconds for time synchronization is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

The ±2 milliseconds accuracy requirement specified in this standard is realistically achievable with equipment available and proper cabling installation.

Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset.

R11. Each Transmission Owner and Generator Owner shall provide all SER, FR, and DDR data for the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 The recorded data will be provided within 30 calendar days of a request.

11.2 The recorded data will be retrievable for the period of 10 calendar days preceding a request.

11.3 SER data will be provided in Comma Separated Value (.CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic C37.111, (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records, (2) device specification and configuration, or (3) actual data recordings.

Rationale for R11:

Multiple entities and data recordings may be involved in wide-area disturbance analysis. Standardized file format and naming conventions improves timely analysis.

The DMSDT determined that providing the data within 30 calendar days is reasonable based on normal business operations workload.

For Part 11.2, the DMSDT intends for data to be available for 10 days preceding a request for that data. Requests are usually initiated the same or next day following an event for which data is requested. A 10 calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requester of data has to be aware of the Part 11.2 10 day retrievability. Realistic overwrite concerns may have to consider the recording capability implemented.

Part 11.4 specifies the IEEE C37.111-2013 COMTRADE format for the FR and DDR data. IEEE C37.111 is the Standard for Common Format for Transient Data Exchange, and it is well established in industry. It is necessary to specify a standard format as it will be incorporated with other submitted data to provide a detailed analysis of a power system disturbance. C37.111-2013 is a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, restore the recording capability or develop a timeline for restoration and a Corrective Action Plan (CAP) for submission to the Regional Entity:*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, or (3) dated CAP transmittals to the Regional Entity.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. Therefore, it is required to return the data recording capability to service within 90 calendar days of a discovery of failure. If the Disturbance Monitoring Equipment (DME) cannot be returned to service within 90 calendar days (e.g. budget cycle, service crews, vendors, etc.), the Entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. For example, DDR data from a generator may not be restored until the next outage cycle.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 80% but less than 100% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 70% but less than or equal to 80% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by greater than 10 calendar days but less than or equal to 20	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 60% but less than or equal to 70% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by greater than 20 calendar days but less than or equal to 30	The Transmission Owner identified the BES buses as directed by Requirement R1for less than or equal to 60% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying one or more other owners by greater than 30 calendar days.

				calendar days.	calendar days.	
R2	Long-term Planning	Lower	Each Transmission or Generator Owner as directed by Requirement R2 had more than 75% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission or Generator Owner as directed by Requirement R2 had more than 50% but less than or equal to 75% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission or Generator Owner as directed by Requirement R2 had more than 10% but less than or equal to 50% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission or Generator Owner as directed by Requirement R2 had from 0% but less than or equal to 10% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 75% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 50% but less than or equal to 75% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 10% but less than or equal to 50% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 0% but less than or equal to 10% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.

R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 0% but less than or equal to 10% of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for more than 80% but less than 100% of the required BES Elements. OR The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by 30 calendar days or less. OR The Responsible Entity as directed by Requirement R5 was	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required BES Elements. OR The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Responsible Entity	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required BES Elements. OR The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Responsible Entity	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for less than or equal to 60% of the required BES Elements. OR The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by greater than 90 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying one or

			late in notifying the owners by 10 calendar days or less.	as directed by Requirement R5 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.	as directed by Requirement R5 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.	more owners by greater than 30 calendar days.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.

R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 75% but less than 100% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 50% but less than or equal to 75% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 0% but less than or equal to 50% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 10% of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 90% but less than 100% of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization for SER, FR, and DDR data for less than or equal to 70% of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30 calendar days but less than 40 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40 calendar days but less than or equal to 50 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50 calendar days but less than or equal to 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide less than or equal to

			11.2 provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% of the data but less than 100% of the data in the proper data format.	11.2 provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% of the data but less than or equal to 90% of the data in the proper data format.	11.2 provided more than 70% but less than or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% of the data but less than or equal to 80% of the data in the proper data format.	70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days but less than or equal to 100 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days but less than or equal to 110 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days but less than or equal to 120 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111-2013, Measuring relays and protection equipment Part 24: Common format for transient data exchange (COMTRADE) for power systems. Standard published 04/30/2013 by IEEE.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for Sequence of Events Recording (SER) and Fault Recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20%.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1500 MVA or
- 20% of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 11 or fewer BES buses:</u> FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9.

<u>If the list has more than 11 BES buses: SER and FR </u>data is required on at least the 10% of the BES buses, determined in Step 6, with the highest maximum available

calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20% of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data, therefore the following types of BES buses are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2
Sequence of Events Recording (SER) Data Format
(Requirement R11, Part 11.3)

Date	Time	Local Time Offset from UTC	Substation	Device	State[1]
08/27/13	23:58:57.110	EST	Sub 1	Breaker 1	Close
08/27/13	23:58:57.082	EST	Sub 2	Breaker 2	Close
08/27/13	23:58:47.217	EST	Sub 1	Breaker 1	Open
08/27/13	23:58:47.214	EST	Sub 2	Breaker 2	Open

[1] Acceptable states are either "OPEN" or "CLOSE". Other status monitoring indications can be used for devices other than circuit breakers.

Guidelines and Technical Basis

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Assessment
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Assessment
R5	RE (PC | RC)	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance Monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance Monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a system configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R1:

Sequence of events and fault records for the analysis, reconstruction, and reporting of system disturbances is important. However, SER and FR data are not required at every BES bus on the BES to conduct adequate or thorough analysis of a disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuit sallow precise reconstruction of events of both localized and wide-area disturbances.

In addition, more quality information is always better than less when performing event analysis. However, 100% coverage of all elements is not practical or required for effective analysis of wide-area disturbance. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses where crucial information is available when required.
2. Excessive overlap of coverage is avoided.
3. Avoid gaps in critical coverage.
4. Provide coverage of system elements that could propagate a disturbance.
5. Avoid mandates to cover system elements that are more likely to be a casualty of a disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of transmission lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish bright line criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of transmission systems throughout the continent to analyze transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright-line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause electric system cascading outages.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater system impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for systems with more than 11 BES buses with three phase short circuit levels above 1500 MVA.

1. Total number of BES buses in the transmission system under evaluation.
    a. Only tangible substation or switchyard buses are included.
    b. Pseudo buses created for analysis purposes in system models are excluded.
2. Determine the three phase short circuit MVA for each bus.
3. Exclude buses from the list with short circuit levels below 1500 MVA.
4. Determine the median short circuit for the top 11 buses on the list (position number 6).
5. Multiply median short circuit level by 20%.
6. Reduce the list of BES buses with short circuit levels higher than 20% of the median.
7. Apply SER and FR at buses with short circuit levels in the top 10% of the list (from 6).
8. Apply SER and FR at buses at an additional 10% of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
    - Electrically distant BES buses or electrically distant from other DME devices
    - Voltage sensitive areas
    - Cohesive load and generation zones
    - BES buses with a relatively high number of incident transmission circuits
    - BES buses with reactive power devices
    - Major facilities interconnecting outside the Transmission Owners' area.

For event analysis purposes, more valuable information is attained about generators and their response to system events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The reevaluation interval of five years was chosen based upon the experience of the DMSDT to address changing system configurations while creating balance in the frequency of reevaluations.

Guideline for Requirement R2:

Analyses of wide-area disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. SER data for generator breaker operations provides little useful data of generator loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers connected to the Transmission Owner's bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission lines

Only those Elements that are identified as BES as identified in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100 kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the transmission system will be captured by FR data on the transmission system.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a transmission system is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:
$\mathbf{I}_r = 3\bullet\mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings
Voltages are to be recorded at applicable BES buses. Note that the Requirement calls for the voltages to be determinable. There are two options for recording phase-to-neutral voltages at applicable BES buses:

1. At terminals of each line. This option would apply to lines that have a full set of VTs/CVTs required for distance protections, which is quite common in practice.
2. At a particular BES bus, in which case all the BES Elements connected to that common BES bus are covered.

Guideline for Requirement R4:

This requirement directs the applicable entities having FR determined as identified in Requirement R1 that meets the following:

Requirement R4, Part 4.1 specifies the minimum amount of FR data. Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection system operations after a fault to determine if a protection system operated as designed. Generally speaking, BES faults and the system response to them occur within a very short time period, approximately 1 to 30 cycles, thus a 30 cycle post-trigger record length captured adequate data. Multiple records allow for legacy microprocessor relays which when time synchronized to a common clock are capable of providing adequate fault data but not capable of providing fault data in a single record with 30 cycle post trigger data.

Requirement R4, Part 4.2 specifies the minimum recording rate of FR data. A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for SER.

Requirement R4, Part 4.3 specifies the minimum triggers to ensure FR data is available. A trigger is a set point on an oscilloscope or FR device. The trigger can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area disturbance monitoring to determine the system's electromechanical transient and post-transient response and validate system model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the system's dynamic response and ensuring sufficient coverage to determine system performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historic peak Demand. This DDR data is included to provide adequate system wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a disturbance helps the analysis of large Disturbances. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.

- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.
- The information in the spreadsheet does not provide information by which the plant location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA”. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47% of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5% of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, Part 5.1.2 is included to capture larger units located at large generating plants which could pose a stability risk to the system if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. The incremental impact to the number of units requiring monitoring is expected to be relatively low.

Major transmission interfaces are explicitly defined based on the Interconnection since a common naming convention for these interfaces does not exist. However, this data may be calculated, rather than directly measured if the accurate quantity can be derived (e.g. either end of the Flowgate line could be monitored since the other end could be derived). In the Western Interconnection, these major transmission interfaces are defined by the Regional Entity. In the ERCOT and Quebec Interconnections, the Responsible Entity will be required to identify those interfaces that are deemed significant enough to require monitoring (i.e. are utilized for real-time limits such as System Operating Limits or “contingencies”). Only one BES Element associated with a major transmission interface needs DDR data capability.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability could be captured on the BES. For example, a major 500kV or 230kV substation on the EHV system close to the load pocket where the UVLS is deployed would likely be a valuable BES Element for DDR coverage and would aid in post-disturbance analysis of the load area’s response to large system deviations (voltage, frequency, etc.). It is intended to have DDR data for “Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.”

Guideline for Requirement R6:

DDR data shows transient response to system disturbances after fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. For example, a breaker-and-a-half or double bus configuration has a North (or East) Bus and South (or West) Bus, would require that both buses should have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a system configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current record is also acceptable.

For all circuits where current recording is required, real and reactive power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6, apply to Requirement R7. Since either of the high or low-side windings of the generator step up (GSU) transformer may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a system configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Large scale system outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high or low frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in system frequency which could be caused by large changes in generation or load, or possibly changes in system impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85% is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power system to a disturbance and is used for analyzing complex power system events. This recording is typically used to capture short term and long term disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency in sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of ±2 milliseconds for time synchronization is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

The ±2 milliseconds accuracy requirement specified in this standard is realistically achievable with equipment available and proper cabling installation.

Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset.

Guideline for Requirement R11:

This requirement directs the applicable entities that upon requests from the Reliability Coordinator, Regional Entity or NERC to provide SER, FR data for BES buses determined in requirement R1 and DDR data for BES Elements determined per requirement R5. To facilitate the analysis of BES disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor.

Requirement R11, Part 11.2 specifies that the minimum time period of 10 calendar days for which the data will be retrievable preceding a request. With the equipment in use that has the capability of recording data, having the data retrievable for the 10 calendar days preceding a request is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10 calendar day time frame, an incident occurs on a Day 1. If a request for data is made on Day 6, then that data has to be provided to the requester within 30 calendar days. However, if a request for the data is made on Day 11, that is outside the 10 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (.CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power system disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange it is well established in the industry. It is necessary to specify a standard format as it will be incorporated with other submitted data to provide a detailed analysis of a power system disturbance. C37.111-2013 is a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for the naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files first version was approved in 2007. From the August 14, 2003 blackout there was thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and because of that it became difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements which had been established in Requirements R1 and R5 and are found to be out of service. The owners are to return the capability to service within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out of service does not result in lack of sufficient data for coverage of the system. Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to return the capability to service within 90 calendar days, the requirement further provides that, for such cases, the entity must develop a timeline and a Corrective Action Plan (CAP) for submission to the Regional Entity. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

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

Development Steps Completed

1. Nominations for the SAR Drafting Team members were solicited February 26 – March 9, 2007.
2. The SAR was posted for a 30-day comment period March 22 – April 20, 2007.
3. Nominations for the Disturbance Monitoring Standard Drafting Team (~~SDT~~DMSDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.
4. The project was placed into informal development the fall of 2010.
5. The project was placed into formal development January 2013.
6. Nominations for two additional ~~SDT~~DMSDT members were solicited April 12 – 25, 2013.
7. Three additional ~~SDT~~DMSDT members were added May 22, 2013.
8. Industry webinar was held May 22, 2013.
9. Industry technical conferences were held July 30 - 31, 2013 and August 6 - 7, 2013.
10. The draft standard was posted for a 45-day concurrent comment and ballot period November 1 – December 16, 2013.

Description of Current Draft

This is the second draft of the proposed standard and is being posted for stakeholder comments and additional ballot. This draft includes the modifications based on comments submitted by stakeholders

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with a 10-day Ballot	May 2014
Final Ballot	July 2014
BOT Adoption	August 2014

Effective Dates

The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

~~See PRC-002-2~~

Implementation Plan.

Implementation Plan for PRC-002-2 Requirements R1 and R5:

Entities shall be 100% compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirement R12:

Entities shall be 100% compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:

Entities shall be at least 50% compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date.

Entities that own only one (1) identified BES bus location, Element, or generating unit shall be fully compliant within six (6) years of the Effective Date.

- **Note**: Entities that own only one (1) identified BES bus, BES Element, or generating unit and are notified by an entity shall be 100% compliant within four (4) years following notification.

Entities shall be 100% compliant with a reassessed list from Requirement R1or R5 within three (3) years following notification of the list.

Version History

Version	Date	Action	Change Tracking
2.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms (Glossary) used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

When this standard has received ballot approval, the ~~text boxes~~Rationale Boxes will be moved to the ~~Application~~ Guidelines and technical Basis Section of the Standard.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.

~~3.~~**4. Applicability:**

Functional Entities:

4.1 The Responsible Entity is:

~~3.1.1~~4.1.1 Eastern Interconnection – Planning Coordinator

4.1.2 –ERCOT – Planning Coordinator or Reliability Coordinator

4.1.3 Western Interconnection – Reliability Coordinator

4.2 Transmission Owner

4.3 Generator Owner

Rationale for Functional Entities:

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

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

~~Rationale for Functional Entities:~~

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

~~BES Buses where Fault Recorder (FR) and Sequence of Events Recorder (SOER) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available.~~

B. Requirements and Measures

R1. Each Transmission Owner shall identify BES buses for which sequence of events ~~recorder~~recording (SER) and fault ~~recorder~~recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify ~~within 90 calendar days~~ other owners~~, if any,~~ of BES Elements connected to those BES buses~~.~~, if any, within 90 calendar days that those BES Elements may require SER data and/or FR data, and reevaluate the identified BES buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. The Transmission Owner has a dated (electronic or ~~hardcopy~~hard copy) list of BES buses for which SER and FR data are required, identified in accordance with Attachment 1, ~~assessed~~and evidence that the bus identification has been reevaluated within the required interval. The Transmission Owner will also have dated (electronic or ~~hardcopy~~hard copy) evidence that it notified other owners in accordance with Requirement R1.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Requirement R1 directs a uniform methodology to identify these BES buses. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of transmission lines and other Elements connected to the bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on system reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause large cascading system events, so SER and FR data from these BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment. Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection.

For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data are required, based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and system topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data are required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. SER and FR data will include generating resource contributions to an event. DDR data better shows generator response to disturbances.

Each Transmission Owner must reevaluate the list of BES buses every five calendar years to address system changes.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90 calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

~~Rationale for R1:~~

~~SER and FR data are not required from every location on the BES to conduct adequate analysis of a BES event; SER and FR from key locations on the BES will suffice. Requirement R1 directs a uniform methodology to select these locations.~~

~~Review of actual BES short circuit data received from the industry in response to the DMSDT's June 5, 2013 through July 5, 2013 data request illuminated a strong correlation between the available short circuit MVA at a transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of transmission lines and other Elements connected to the bus, and (iii) the number and size of generating units connected to the bus. Buses with a large short circuit MVA level Elements that have a significant effect on system reliability and performance. Conversely, buses with very low short circuit MVA level seldom cause large cascading system events, so FR and SER typically are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment. Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected locations. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection.~~

~~For the purpose of PRC-002-2, there are a minimum number of buses for which FR and SER are required based on the short circuit level, With these concepts and the objective being sufficient recording coverage for event analysis, the SDT developed a procedure included in Attachment 1, that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for FR and SER data regardless of variations in size and system strength of Transmission Owners across all the Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process.~~

~~BES buses where FR and SER data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their systems to determine these buses. SER and FR data will reflect generating resource contributions to an event. DDR data better shows generator response to disturbances.~~

~~Each Transmission Owner must reevaluate the list of buses every five calendar years to address system changes such. Since there may be multiple owners of equipment that comprise a bus, the notification required in R1 is necessary to ensure all owners are notified.~~

~~To ensure effective and timely post-event analysis, it is important to have continuity of SER and FR, with sufficient data from bus locations across the BES. Of the BES bus locations determined in Requirement R1, there may be locations where the Transmission Owner of the bus location does not own all the Elements. This requirement ensures that all necessary BES Elements at a selected bus location have SOER and FR data available by requiring the Transmission Owner of that bus location to notify the other owners of their respective BES Elements that they require SER and FR per this standard. A 90 calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.~~

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

M2. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which can include a single design standard as representative for common installations; or (2) actual data recordings.

Rationale for R2:

The intent is to capture SER data (opening/closing) for the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance. Other status monitoring indications can be used for devices other than circuit breakers.

~~Rationale for R3:~~

~~The intent is to capture SER data (opening/closing) for the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, timestamped, as per Requirement R10 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance.~~

R3. Each Transmission Owner and Generator Owner shall have the following FR data to determine the following electrical quantities ~~at~~for each of the BES Elements they own connected to the BES buses identified ~~per~~in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltages for each phase of each specified ~~line or~~ BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1. Transformers that have a low-side operating voltage of 100kV or above.

3.~~2.~~2.2 Transmission lines.

M3. ~~**M3.**~~ The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) of FR data is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations including a single design standard as a representation for common installations; or (2) actual data recordings or derivations.

~~Rationale for R4:~~

~~The required electrical quantities may either be directly measured or derived if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all phase-to-neutral voltages are required to be determinable for each BES Bus identified in Requirement R1. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high side or the low side of the transformer.~~

Rationale for R3:

The required electrical quantities may either be directly measured or derivable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for system disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a post-trigger record length of at least 30 cycles for the same trigger point~~.~~, or
- At least two cycles of the pre-trigger data, the first three cycles of the ~~fault~~post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2~~.~~ A minimum recording rate of 16 samples per cycle.

4.3~~.~~ Trigger settings for at least the following:

4.3.1. Neutral (residual) overcurrent.

4.3.2. Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) that FR data meets Requirement ~~R5~~R4. Evidence may include, but is not limited to: (1) device specification (R4, Part 4.2) and configuration (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

~~Rationale for R4:~~

~~Time-stamped pre- and post-trigger fault data aid in the analysis of power system operations and determination if operation were as designed. System faults generally persist for a short time period, approximately 1 to 50 cycles; thus, a 50 cycle post-trigger minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 50 contiguous cycles post-trigger.~~

~~A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point-on-wave data for recreating accurate fault conditions.~~

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power system operations and determination if operations were as designed. System faults generally persist for a short time period, thus, a 30 cycle post-trigger minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30 contiguous cycles post-trigger.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

R5. Each Responsible Entity ~~(Planning Coordinator or Reliability Coordinator, as applicable)~~ shall identify BES Elements for which dynamic disturbance ~~recorder~~recording (DDR) data is required, notify ~~within 90 calendar days~~ other owners~~, if any,~~ of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1. The BES Elements shall include the following:

5.1.1. Generating resource(s) with:

- ~~5.1.1.1.~~ Gross individual nameplate rating greater than or equal to 500 MVA~~.~~, or
- ~~5.1.1.2~~ Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to ~~1000MVA.~~ 1000 MVA.

5.1.2. Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines:

- Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection, or
- Transfer Paths in the Western Interconnection Path Rating Catalog, or
- Voltage stability limited transfer paths or load serving area, or
- Interfaces between Balancing Authority Areas, or
- Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC~~)~~).

5.1.3. Each terminal of a high~~-~~ voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4. One or more BES Elements associated with Interconnection Reliability Operating Limits~~.~~ (IROLs).

5.1.5. Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.

5.2. The BES Elements shall include a minimum of:

5.2.1 One BES Element.

5.2.2 One additional BES Element ~~per~~for each additional 3,000 MW of its historical peak system Demand.

M5. The Responsible Entity has a dated (electronic or ~~hardcopy~~hard copy) list of BES Elements for DDR data, identified in accordance with Requirement R5, assessed within the required interval, dated evidence (electronic or ~~hardcopy~~hard copy) of notification to each Transmission Owner or Generator Owner of Elements identified in Requirement R5. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R5:

DDR plays a crucial role in wide-area disturbance analysis, and the Responsible Entity needs to ensure that there are sufficient BES Elements identified for DDR data capture. Additionally, DDR is used for capturing the Bulk Electric System transient and post-transient response and for validating the system performance. The requirement for DDR data for identified BES Elements, for the purpose of this standard, is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-assessment of the list is a reasonable interval for this review.

The DDR data is to be captured for a BES Element, and with the exception of HVDC, is obtainable from one terminal of an Element. This pertains to "major transmission interfaces".

For HVDC (Part 5.1.3), each Transmission Owner is only responsible for DDR data for the Elements that it owns.

Part 5.1.5 is intended to have DDR data for at least one BES Element in a portion of the BES with a voltage response for system events that has required the installation of a UVLS.

It is intended that a Responsible Entity will have DDR data for one BES Element and one additional BES Element for each 3,000 MW of its historical peak system Demand.

Communication of selected Elements is required to ensure that the owners of the respective Elements are aware of their responsibilities under this standard. The Responsible Entity is only required to share the list of required Elements that each Transmission Owner and Generator Owner owns.

~~Rationale for R5:~~

~~DDR plays a crucial role in wide area disturbance analysis, and the Responsible Entity needs to ensure that there are sufficient BES Elements identified for DDR data capture. Additionally, DDR is used for capturing the Bulk Electric System transient and post-transient response and for validating the system performance. The requirement for DDR for identified BES Elements, for the purpose of this standard, is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis.~~

~~From its experience with changes to the Bulk Electric System that would affect DDR, the SDT decided that the five calendar year re-assessment of the list is a reasonable interval for this review.~~
~~The DDR data is to be captured for a BES Element, and with the exception of HVDC, is obtainable from one terminal of an Element.~~

~~For HVDC (Part 5.1.3), each Transmission Owner is only responsible for DDR data for the Elements that it owns.~~

~~Sub-Part 5.1.5 is intended to have DDR data for at least one BES Element in a portion of the BES with a voltage response for system events that has required the installation of a UVLS.~~

~~It is intended that a Responsible Entity will have DDR data for one BES Element, and one more BES Element for each 3,000 MW of its historical peak system Demand.~~

~~Communication of selected Elements is required to ensure that the owners of the respective Elements are aware of their responsibilities under this standard. The Responsible Entity is only required to share the list of required Elements that each Transmission Owner and Generator Owner owns.~~

R6. Each Transmission Owner shall have DDR data for each BES Element ~~they own~~it owns for which it received notification as ~~per~~identified in Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three-~~-~~phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or ~~hardcopy~~hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

Rationale for R6:

Dynamic disturbance recording is used for measurement of transient response to system disturbances, during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the buses within a location are at the same frequency one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a system configuration assuming all normally closed circuit breakers on a bus are closed.

~~Rationale for R6:~~

~~Dynamic Disturbance Recording is used for measurement of transient response to system disturbances, during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined--calculated, derived, etc.~~

~~Because all of the buses within a location are at the same frequencies one frequency measurement is adequate. The data requirements for PRC-002-2 are based on a system configuration assuming all normally-closed circuit breakers on a bus are closed.~~

R7. Each Generator Owner shall have DDR data for each BES Element ~~they own as per~~it owns and is notified according to Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step~~-~~ up (GSU) transformer high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three~~-~~ phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. ~~–~~The Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) of DDR data to determine electrical quantities as specified in Requirement ~~R9~~R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings or derivations.

~~Rationale for R7:~~

~~A crucial part of wide area disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up (GSU) transformer, measuring the specified electrical quantities, to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how.' GOs may install this capability or, where the TO already has suitable DDR data, contract with the TO. However, the Generator Owner is still responsible for the provision of this data.~~

Rationale for R7:

A crucial part of wide-area disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high or low-side of the generator step up (GSU) transformer, measuring the specified electrical quantities, to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how.' Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

R8. Each Transmission Owner and Generator Owner ~~that is~~ responsible for DDR data ~~as per~~in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

~~-~~**8.1** Triggered record lengths of at least three minutes.

8.2.~~ –~~ At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds.

~~no lower than 85% of normal operating voltage for a duration of 5 seconds~~

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or ~~hardcopy~~hard copy) of data recording and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations; or (2) actual data recordings.

Rationale for R8:

Large scale system outages generally are an evolving sequence of events that occur over an extended period of time, making DDR essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

~~Rationale for R8:~~

~~Large scale system outages generally are an evolving sequence of events that occur over an extended period of time, making DDR essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data are available for the entire Disturbance.~~

~~Existing DDR recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).~~

R9. Each Transmission Owner and Generator Owner in Requirement R5 shall have DDR data~~, for the Elements as per Requirement R5, which conform~~ that conforms to the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings (R9, Part 9.2).

Rationale for R9:

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle, on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power system disturbances.

~~Rationale for R9:~~

~~An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle, on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.~~

~~An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor low frequency oscillations typically of interest during power system disturbances.~~

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER, FR and DDR data for the BES ~~bus~~ buses identified ~~per~~in Requirement R1 and BES Elements identified ~~per~~in Requirement R5 to within ± 2 milliseconds of Coordinated Universal Time (UTC), time stamped with or without a local time offset. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M10. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy)~~hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) device specification and configuration, or (2) actual data recordings, or (3) station drawings.

~~Rationale for R10:~~

~~Time synchronization of disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.~~

~~Accuracy of ±2 milliseconds for time synchronization is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:~~

~~“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”~~

~~Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:~~

~~“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”~~

~~From NPCC’s SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.~~

~~The ±2 milliseconds accuracy requirement specified in this standard is realistically achievable with equipment available and proper cabling installation.~~

~~Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset.~~

Rationale for R10:

Time synchronization of disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of ±2 milliseconds for time synchronization is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

The ±2 milliseconds accuracy requirement specified in this standard is realistically achievable with equipment available and proper cabling installation.

Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset.

R11. Each Transmission Owner and Generator Owner shall provide all SER, FR, and DDR data for the BES ~~bus locations~~buses identified ~~per~~in Requirement R1 and BES Elements identified ~~per~~in Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1. The recorded data will be provided within 30 calendar days of a request.

11.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request.

11.3. SER data will be provided in Comma Separated Value (.CSV) format following Attachment 2.

11.4. ~~.~~ FR and DDR data will be provided in electronic C37.111, (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files.

11.5. ~~.~~ Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

M11. The Transmission Owner or Generator Owner has evidence (electronic or ~~hardcopy~~hard copy) data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records, (2) device specification and configuration, or (3) actual data recordings.

Rationale for R11:

Multiple entities and data recordings may be involved in wide-area disturbance analysis. Standardized file format and naming conventions improves timely analysis.

The DMSDT determined that providing the data within 30 calendar days is reasonable based on normal business operations workload.

For Part 11.2, the DMSDT intends for data to be available for 10 days preceding a request for that data. Requests are usually initiated the same or next day following an event for which data is requested. A 10 calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requester of data has to be aware of the Part 11.2 10 day retrievability. Realistic overwrite concerns may have to consider the recording capability implemented.

Part 11.4 specifies the IEEE C37.111-2013 COMTRADE format for the FR and DDR data. IEEE C37.111 is the Standard for Common Format for Transient Data Exchange, and it is well established in industry. It is necessary to specify a standard format as it will be incorporated with other submitted data to provide a detailed analysis of a power system disturbance. C37.111-2013 is a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER ~~and~~, FR ~~data at the BES buses identified per Requirement R1~~ or DDR data ~~for the BES Elements identified per Requirement R5, shall~~, restore the recording capability or develop a timeline for restoration and a Corrective Action Plan (CAP ~~), to be submitted~~) for submission to the Regional Entity ~~, to restore the recording ability which includes a timeline for the restoration.:~~ ~~[~~:*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or ~~hardcopy~~hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, or (3) dated CAP transmittals to the Regional Entity.

~~Rationale for R12:~~

~~Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. Therefore, it is required to return the data recording ability to service within 90 calendar days of a discovery of failure. If the Disturbance Monitoring Equipment (DME) cannot be returned to service within 90 calendar days (e.g. budget cycle, service crews, vendors, etc.), the Entity must report it to the Regional Entity along with a Corrective Action Plan for returning the equipment to service. The timeline required for the CAP depends on the entity and they type of data required. For example, DDR data from a generator may not be restored until the next outage cycle. A CAP is not necessary if the recording capability is restored within 90 day of the discovery of the failure.~~

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90 calendar days to ensure that adequate data is available for event analysis. Therefore, it is required to return the data recording capability to service within 90 calendar days of a discovery of failure. If the Disturbance Monitoring Equipment (DME) cannot be returned to service within 90 calendar days (e.g. budget cycle, service crews, vendors, etc.), the Entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. For example, DDR data from a generator may not be restored until the next outage cycle.

~~Rationale for R11:~~

~~Multiple entities and data recordings may be involved in wide area disturbance analysis. Standardized file format and naming conventions improves timely analysis.~~

~~The SDT determined that providing the data within 30 calendar days is reasonable based on normal business operations workload. A 10 calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities how long the data will be available.~~

~~For Part 11.2, the SDT intends for data to be available for 10 days preceding a request for that data. Requests are usually initiated the same or next day following an event for which data is requested. A 10 calendar day time frame provides a practical limit on the amount of data required to be stored and lets the requesting entities how long the data will be available. The requester of data has to be aware of the Part 11.2 10 day retrievability.~~

~~Realistic overwrite concerns may have to consider the recording capability implemented.~~

~~Part 11.4 specifies the IEEE C37.111-2013 COMTRADE format for the FR and DDR data. IEEE C37.111 is the Standard for Common Format for Transient Data Exchange, and it is well established in the industry. It is necessary to specify a standard format as it will be incorporated with other submitted data to provide a detailed analysis of a power system disturbance. C37.111-2013 is a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Responsible Entity ~~(Planning Coordinator or Reliability Coordinator)~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 80% but less than 100% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by 10 calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 70% but less than or equal to 80% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 60% but less than or equal to 70% of the required BES buses. OR The Transmission Owner assessed the BES buses- as directed by Requirement R1 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by	The Transmission Owner identified the BES buses as directed by Requirement R1for less than or equal to 60% of the required BES buses-. OR The Transmission Owner assessed the BES buses as directed by Requirement R1but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying one or more other owners by

				greater than 10 calendar days but less than or equal to 20 calendar days.	greater than 20 calendar days but less than or equal to 30 calendar days.	greater than 30 calendar days.
R2	Long-term Planning	Lower	Each Transmission or Generator Owner as directed by Requirement ~~R3~~R2 had more than 75% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the ~~bus locations as per~~BES buses identified in Requirement ~~R2~~R1.	Each Transmission or Generator Owner as directed by Requirement ~~R3~~R2 had more than 50% but less than or equal to 75% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the ~~bus locations as per~~BES buses identified in Requirement ~~R2~~R1.	Each Transmission or Generator Owner as directed by Requirement ~~R3~~R2 had more than 10% but less than or equal to 50% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the ~~bus locations as per~~BES buses identified in Requirement ~~R2~~R1.	Each Transmission or Generator Owner as directed by Requirement ~~R3~~R2 had from 0% but less than or equal to 10% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the ~~bus locations as per~~BES buses identified in Requirement ~~R2~~R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 75% but less than 100% of the total	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 50% but less than or equal to 75% of	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 10% but less than or equal to 50% of	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 0% but less than or equal to 10% of

			set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities ~~per~~for each BES Element.	the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities ~~per~~for each BES Element.	the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities ~~per~~for each BES Element.	the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities ~~per~~for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had- FR data that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 0% but less than or equal to 10% of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for more than 80% but less than 100% of the required BES Elements. OR	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required BES Elements. OR	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required BES Elements. OR	The Responsible Entity accurately identified the BES Elements for DDR as directed by Requirement R5 for less than or equal to 60% of the required BES Elements. OR

			The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by 30 calendar days or less. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by 10 calendar days or less.	The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.	The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.	The Responsible Entity assessed the BES Elements for DDR as directed by Requirement R5 but was late by greater than 90 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying one or more owners by greater than 30 calendar days.
R6	Long-term Planning	Lower	The Transmission Owner- had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 75% but less than 100% of the total required electrical quantities for all	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for	The Transmission Owner failed to ~~had~~have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			applicable BES Elements.	all applicable BES Elements.	all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 75% but less than 100% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 50% but less than or equal to 75% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 0% but less than or equal to 50% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 75% but less than 100% of the total recording properties as	The Transmission Owner or Generator Owner had DDR data that meets more than 50% but less than or equal to 75% of the total recording	The Transmission Owner or Generator Owner had DDR data that meets more than 10% but less than or equal to 50% of the total recording	The Transmission Owner or Generator Owner had DDR data that meets ~~more than 1% but~~ less than or equal to 10% of the total recording

			specified in Requirement R9.	properties as specified in Requirement R9.	properties as specified in Requirement R9.	properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 90% but less than 100% of the ~~bus locations as per Requirements~~BES buses identified in Requirement R1 and BES Elements ~~as per~~identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the ~~bus locations as per Requirements~~ BES buses identified in Requirement R1 and BES Elements ~~as per~~identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the ~~bus locations as per Requirements~~ BES buses identified in Requirement R1 and BES Elements ~~as per~~identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization for SER, FR, and DDR data for less than or equal to 70% of the ~~bus locations as per Requirements~~ BES buses identified in Requirement R1 and BES Elements ~~as per~~identified in Requirement R5 as directed by Requirement R10.

R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30 calendar days but less than 40 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part ~~113~~11.2 provided more than 90% but less than	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40 calendar days but less than or equal to 50 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided more than 80% but less than	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50 calendar days but less than or equal to 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided more than 70% but less than	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide less than or equal to

			100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% of the data but less than 100% of the data in the proper data format.	or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% of the data but less than or equal to 90% of the data in the proper data format.	or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% of the data but less than or equal to 80% of the data in the proper data format.	70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days but less than or equal to 100 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days but less than or equal to 110 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days but less than or equal to 120 calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111-2013, Measuring relays and protection equipment Part 24: Common format for transient data exchange (COMTRADE) for power systems. Standard published 04/30/2013 by IEEE.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

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U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout~~, November~~ in the United States and Canada (Nov. 2003~~, in the United States and Canada~~)

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events ~~Recorder~~Recording (SER) and Fault ~~Recorder~~Recording (FR) Data

~~Locations Selection Methodology~~

(Requirement R1)

To identify monitored BES ~~bus locations~~buses for Sequence of Events ~~Recorder~~Recording (SER) and Fault ~~Recorder~~Recording (FR) data required by Requirement 1~~ of PRC-002-2~~, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus~~ location~~ includes physical buses connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus~~ locations~~.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer ~~bus locations~~buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20%.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1500 MVA or
- 20% of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 11 or fewer BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9.

If the list has more than 11 BES buses: ~~FR~~SER and ~~SER~~FR data is required on at least the 10% of the BES buses, determined in Step 6, with the highest maximum

available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. ~~FR~~SER and ~~SER~~FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20% of the BES ~~bus~~buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for ~~FR~~SER and ~~SER~~FR data, therefore the following types of BES buses are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored ~~locations~~BES buses for ~~FR~~SER and ~~SER~~FR data for ~~PRC-002-2~~ Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events ~~Recorder~~Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date	Time	Local Time Offset from UTC	Substation	Device	State[1]
08/27/13	23:58:57.110	EST	Sub 1	Breaker 1	Close
08/27/13	23:58:57.082	EST	Sub 2	Breaker 2	Close
08/27/13	23:58:47.217	EST	Sub 1	Breaker 1	Open
08/27/13	23:58:47.214	EST	Sub 2	Breaker 2	Open

[1] Acceptable states are either "OPEN" or "CLOSE". Other status monitoring indications can be used for devices other than circuit breakers.

Guidelines and Technical Basis

High Level Requirement Overview

Requirement	Entity	Identify ~~Bus Locations~~ BES Buses	Notification	SER	FR	5 Year Assessment
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Assessment
R5	RE (PC | RC)	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance Monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance Monitoring capability to ensure the completeness of BES data capture.

~~From a compliance perspective, questions have been raised by industry regarding how conformance to this standard would be judged during a natural disaster which most likely would cause abnormal system conditions for the capturing of data that PRC-002-02 addresses, and also cause the loss of Disturbance Monitoring capability. This is addressed by NERC in its Appendix 4B Sanction Guidelines of the North American Electric Reliability Corporation, Section 2 Basic Principles, Section 2.8 Extenuating Circumstances effective Dec. 20, 2012:~~

~~"In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate penalties."~~

The data requirements for PRC-002-2 are based on a system configuration assuming all normally~~-~~ closed circuit breakers on a bus are closed.

Guideline for Requirement R1:

Sequence of events and fault records for the analysis, reconstruction, and reporting of system disturbances is important. However, SER and FR data are not required at every ~~location~~BES bus on the BES to conduct adequate or thorough analysis of a disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuit sallow precise reconstruction of events of both localized and wide-area disturbances.

In addition, more quality information is always better than less when performing event analysis. However, 100% coverage of all elements is not practical or required for effective analysis of wide-area disturbance. Therefore, selectivity of required ~~locations~~BES buses to monitor is important for the following reasons:

1. Identify key ~~locations~~BES buses where crucial information is available when required.
2. Excessive overlap of coverage is avoided.
3. Avoid gaps in critical coverage.
4. Provide coverage of system elements that could propagate a disturbance.
5. Avoid mandates to cover system elements that are more likely to be a casualty of a disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

~~Listed as follows, the~~The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of transmission lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish ~~a~~ bright line criteria for the application of identified ~~locations~~BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives~~, rather than using opinions, feelings, or anecdotal judgment based upon experience in one area~~.

To answer these questions and establish criteria for ~~location~~BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The ~~team~~MVA Team collected information from a wide variety of transmission systems throughout the continent to analyze transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright-line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective ~~Location Selection Procedure~~Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

~~The Location Selection Procedure~~The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause electric system cascading outages.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater system impact.

To perform the ~~simple~~ calculations of Attachment 1~~ of the standard~~, the following information below is required and the following steps (provided in summary form) are required for systems with more than 11 BES ~~bus locations~~buses with three-phase short circuit levels above 1500 MVA.

1. Total number of BES buses in the transmission system under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in system models are excluded.
2. Determine the three-phase short-circuit MVA for each bus.
3. Exclude buses from the list with short circuit levels below 1500 MVA.
4. Determine the median short circuit for the top 11 buses on the list (position number 6).

5. Multiply median short circuit level by 20%.
6. Reduce the list of BES buses with short circuit levels higher than 20% of the median.
7. Apply SER and FR at buses with short circuit levels in the top 10% of the list (from 6).
8. Apply SER and FR at buses at an additional 10% of the list using engineering judgment, and allowing flexibility to factor in the following considerations~~.~~:
   - ~~a.~~ Electrically distant ~~bus locations~~BES buses or electrically distant from other DME devices
   - ~~b.~~ Voltage sensitive areas
   - ~~c.~~ Cohesive load and generation zones
   - ~~d.~~ ~~Bus locations~~BES buses with a relatively high number of incident transmission circuits
   - ~~e.~~ ~~Bus locations~~BES buses with reactive power devices
   - ~~f.~~ Major facilities interconnecting outside the Transmission Owners' area.

~~There is no requirement for SER and FR for generating units in this standard.~~For event analysis purposes, more valuable information is attained about generators and their response to system events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). ~~For event analysis purposes, more valuable information is attained about generators and their response to system events pre- and post-contingency through DDR data versus SER or FR records~~As a result, this standard only requires DDR data.

The reevaluation interval of five years was chosen based upon the experience~~. Five years is long enough to avoid unnecessary reevaluations, but long enough~~ of the DMSDT to address changing system configurations~~.~~ while creating balance in the frequency of reevaluations.

Guideline for Requirement ~~R3~~R2:

Analyses of wide-area disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. SER ~~of~~data for generator breaker operations provides little useful data of generator loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers ~~at~~connected to the Transmission Owner's bus~~ location. ~~.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The Elements connected to those ~~bus locations~~BES buses for which FR data is required include:

- ~~Transmission lines, including interconnection facilities with generating resources~~
- Transformers with a low-side operating voltage of 100kV or above
- Transmission lines

Only those Elements that are identified as BES as ~~per~~identified in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100 kV are not included.

FR data must be determinable from each terminal of ~~an~~a BES Element connected to applicable BES buses.

Generator step- up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault ~~in~~on the transmission system will be captured by FR data on the transmission system.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The ~~SDT~~DMSDT, after ~~consultating~~consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such ~~FRs~~FR data it is possible to determine all fault types. FR data also ~~augment~~augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a transmission system is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3\bullet\mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$ ~~Equation 1~~

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's ~~law~~Law. Fault currents for one of the BES Elements connected to a particular BES bus ~~location~~

can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus~~ location~~.

Voltage Recordings

Voltages are to be recorded at applicable BES buses. Note that the Requirement calls for the voltages to be determinable. There are two options for recording phase-to-neutral voltages at applicable ~~bus locations~~BES buses:

1. At terminals of each line. This option would apply to lines that have a full set of VTs/CVTs required for distance protections, which is quite common in practice.
2. At a particular BES bus, in which case all the BES Elements connected to that common BES bus are covered.

Guideline for Requirement R4:

This requirement directs the applicable entities having FR determined ~~per~~as identified in Requirement R1 that meets the following:

Requirement R4, Part 4.1 specifies the minimum amount of FR data. Pre- and post~~-~~-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection system operations after a fault to determine if ~~the~~a protection system operated as designed. Generally speaking, BES faults and the system response to them occur within a very short time period, approximately 1 to 30 cycles, thus a 30 cycle post-trigger record length captured adequate data. Multiple records allow for legacy microprocessor relays which when time synchronized to a common clock are capable of providing adequate fault data but not capable of providing fault data in a single record with ~~53~~30 cycle post trigger data.

Requirement R4, Part 4.2 specifies the minimum recording rate of FR data. A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for SER.

Requirement R4, Part 4.3 specifies the minimum triggers to ensure FR data is available. A trigger is a set point on an ~~Oscilloscope~~oscilloscope or ~~Fault Recording~~FR device. The trigger can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area disturbance monitoring to determine the system's electromechanical transient and post-transient response and validate system model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the system's dynamic response and ensuring sufficient coverage to determine system performance, DDR is required ~~at~~for key ~~locations~~BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historic peak Demand. This DDR data is included to provide adequate system~~-~~ wide coverage across an

Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage ~~should~~had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a disturbance helps the analysis of large Disturbances. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The ~~team~~DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The ~~team~~DMSDT determined the following basic information about the generating units of interest (current ~~NA~~North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.
- The information in the spreadsheet does not provide information by which the plant location of each unit can be determined, i.e. the ~~team~~DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the ~~team~~DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA~~.~~". The ~~500MVA~~500 MVA individual unit size threshold was selected because this number roughly accounts for 47% of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5% of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, Part 5.1.2 is included to capture larger units located at large generating plants which could pose a stability risk to the system if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1000 MVA. The ~~300MVA~~300 MVA threshold was chosen based on the ~~Team's~~DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. The incremental impact to the number of units requiring monitoring is expected to be relatively low. ~~Wording was added to cover combined cycle plants, in which the loss of one unit will lead to the loss of a companion unit within a very short period of time. Because of the loss of the entire combined cycle plant, 500MVA was chosen as the threshold.~~

Major transmission interfaces are explicitly defined based on the Interconnection since a common naming convention for these interfaces does not exist. However, this data may be calculated, rather than directly measured~~,~~ if the accurate quantity can be derived (e.g. either end of the Flowgate line could be monitored since the other end could be derived). In the Western Interconnection, these major transmission interfaces are defined by the Regional Entity. In the ERCOT and Quebec Interconnections, the Responsible Entity will be required to identify those interfaces that are deemed significant enough to require monitoring (i.e. are utilized for real-time limits such as System Operating Limits or "contingencies"). Only one BES Element associated with a major transmission interface needs DDR data capability.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective ~~location~~BES Element to monitor for DDR such that action of the UVLS or voltage instability could be captured on the BES. For example, a major 500kV or 230kV substation on the EHV system close to the load pocket where the UVLS is deployed would likely be a valuable ~~location~~BES Element for DDR coverage and would aid in post-disturbance analysis of the load area's response to large system deviations (voltage, frequency, etc.). It is ~~not~~ intended to have DDR data for ~~all areas affected by~~ "Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program."

Guideline for Requirement R6:

DDR data shows transient response to system disturbances after fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. For example, a breaker-and-a-half or double bus configuration has a North (or East) Bus and South (or West) Bus, ~~which~~ would require that both buses should have voltage recording~~,~~ because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a system configuration assuming all normally-closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current record is also acceptable.

For all circuits where current recording is required, real and reactive power will be recorded on a three-phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6, apply to Requirement R7~~, too~~. Since either of the high or low-side windings of the generator step-up (GSU) transformer may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As ~~it~~ was explained in the Guideline for R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a system configuration assuming all normally-closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Large scale system outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist ~~at~~for some ~~locations~~BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high or low frequency excursions of significant size based on the Interconnection size and inertia.
- Rate~~-~~ of~~-~~ change of frequency triggers are used to capture major changes in system frequency which could be caused by large changes in generation or load, or possibly changes in system impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85% is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power system to a disturbance and is used for analyzing complex power system events. This recording is typically used to capture short term and long~~-~~ term disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in ~~Fault Recorder~~FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency in sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine~~-~~ generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement ~~R110:~~ ~~See rationale.~~**R10:** Time synchronization of disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of ±2 milliseconds for time synchronization is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

The ±2 milliseconds accuracy requirement specified in this standard is realistically achievable with equipment available and proper cabling installation.

Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset.

Guideline for Requirement R11:

This requirement directs the applicable entities that upon requests from the Reliability Coordinator, Regional Entity or NERC to provide SER, FR data for BES buses determined in requirement R1 and DDR data for BES Elements determined per requirement R5. To facilitate the analysis of BES disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum ~~timeframe~~time frame of 30 calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor.

Requirement R11, Part 11.2 specifies that the minimum time period of 10 calendar days ~~that~~for which the data will be retrievable preceding a request. With the equipment in use that has the capability of ~~making a~~ recording data, having the data retrievable for the 10 calendar days preceding a request is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10 calendar day time frame, an incident occurs on a Day 1. If a request for data is made on Day 6, then that data has to be provided to the requester within 30 calendar days. However, if a request for the data is made on Day 11, that is outside the 10 calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part ~~1~~11.3 specifies a Comma Separated Value (.CSV) format ~~per~~according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power system disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange it is well established in the industry. It is necessary to specify a standard format as it will be incorporated with other submitted data to provide a detailed analysis of a power system disturbance. C37.111-2013 is a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.

Requirement R11, Part ~~1~~11.5 specifies the IEEE C37.232 COMNAME format for the naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files first version was approved in 2007. From the August 14, 2003 blackout there was thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and because of that it became difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in ~~their~~its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of ~~their~~its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and ~~Generator~~generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements which had been established in Requirements R1 and R5 and are found to be out of service. The owners are to return the capability to service within 90 calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out of service does not result in lack of sufficient data for coverage of the system. Furthermore, 90 calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to return the capability to service within 90 calendar days, the requirement further provides that, for such cases, the entity must ~~provide~~develop a timeline and a Corrective Action Plan (CAP) for submission to the Regional

Entity. These actions are considered to be appropriate to provide for robust and adequate data availability.

The DMSDT developed this Excel Workbook is designed to assist Transmission Owners in using the Median Method for determining monitoring bus locations for Fault Recording and Sequence of Events Recording on their individual systems.

Instructions for use:

For Transmission Owners Only:

1	Organize your short circuit data in the format shown on the Data Input worksheet
2	Your short circuit data should use three phase short circuit with your selected pre-fault voltage
3	Your short circuit data should be ordered from highest three phase short circuit MVA value to lowest three phase short circuit MVA value for all buses greater than 100 kV
4	Your short circuit data should either eliminate or commonly identify non-real buses, zero buses, pseudo buses, or buses which are used for modeling purposes only, by using a common designation for all these type buses that can be eliminated from the Median calculation. It is most common to identify these non-real buses with the number "0" in the bus coded number field.
5	The Data Input Worksheet is designed to have you copy your properly formatted and sorted three phase MVA short circuit data into rows starting at column A row 6 of the worksheet.
6	Data Input, Col. F, is the most important column, it must have the three phase MVA short circuit data values, sorted from highest MVA to lowest MVA. The MVA values in column F, as sorted from highest to lowest MVA, should include all voltage levels greater than or equal to 100 kV.
7	Once you input all of your short circuit data into the Data Input worksheet starting at Column A Row 6, the values in cells B2, B3 and B4 should all be equal. These values should equal the number of rows of short circuit data that you have input. Copy Cell B2 using Cntrl C, then Paste Value, Special value only, back into Cell B2. This should be the total number of rows contained in the data set.
8	If you have zero numbered buses, or pseudo buses, commonly identified by say a number 0 in the bus coded number column, then you need to determine the number of zero numbered buses that are included in this data set.
9	For you to be able to determine this zero bus coded number, you need to select your entire data set, including the header row, from column / row A5 to G___(last row of data). As an example, if your data contains 100 rows, then your highlighted area for sorting and filtering should be A5 to G105. Then using the sort filter command, turn on Filter
10	Once the Filter is on, go to the bus coded number column, pull down the Filter and select only the zero bus coded number rows. The values in cells B3, and B4 should now be equal and indicate the number of zero numbered buses in your data set.
11	We want to store the zero numbered bus rows (number) into cell B4 as a value. To do this, select Cell B4, hit Cntrl C, then hit paste special, value only. This now repalces the formula in Cell B4 with the value of zero buses in the data set.
12	Now we wish to eliminate the zero bus rows from the rest of our data processing, so in the bus coded number column, we want to filter out the zero bus rows, so we reverse the pull down selection by selecting all rows, except the zero bus coded numbered rows. Leave this Filter in place for the rest of the Median method process.
13	If Cell B4 contains the number zero, then Cell F2 should now contain the 6th value down from the highest short circuit MVA value, and Cell G2 should contain 20% of the Cell F2 value. If Cell F2's value is greater than 1500 MVA this is the new lowest MVA value to be used to determine the number of Median selected buses. If the value in F2 is less than 1500 MVA, then we will use 1500 MVA as the lowest value to select the number of Median buses.
14	If Cell B4 contains a value greater than zero, then Cell F2 needs to be replaced with the MVA value contained in the 11th row, column F of the filtered data set. If the value in F2 is less than 1500 MVA then we will use 1500 MVA as the lowest value to select the number of Median buses.
15	With the Filter still applied to our data set, and zero buses deselected, we will need to use the F2 value to apply as the value used for the MVA column pull down.
16	Using Column F, MVA value pull down, use the Number Filter function, greater than or equal to the F2 value. With this Filter F2 number value applied, now Cntrl C Cell C2, and replace C2 with paste special, value only. This now is the number of buses selected by the Median method.
17	You are Finished!!! The number in Cell C2 indicates the number of Median method selected buses, D2 contains the number of total FR and SOER locations, E2 shows the number of FR / SOER for the Top 10% buses and F2 shows the number of FR / SOER for the Distributed 10% buses.
Notes:	Example 1 (Ex 1 without zero buses) is an additional worksheet shown for a system that does not contains any zero buses. All zero bus entries have been eliminated from the data set.
Notes:	Example 2 (Ex 2 with zero buses) is an additional worksheet shown for a system that contains zero buses. Note for a system that contains zero buses, you must observe the row 11, column F MVA value, and place it into Cell F2. In example 2, this MVA value is equal to 5685 MVA, based on the data set provided.

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	0	1	1	0	0	1500
Median Method	0	1	1	0		1500
Zero Busses	0	0	0	0		
Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**	

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	96	20	10	10	5685	1500
Median Method	64	13	7	6		1500
Zero Busses	0	0	0	0		

Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**
19	NCR ID#	FRCC	230	31120	12397
319	NCR ID#	FRCC	230	23087	9197
52	NCR ID#	FRCC	230	17615	7017
58	NCR ID#	FRCC	230	17039	6788
56	NCR ID#	FRCC	230	16472	6562
23	NCR ID#	FRCC	230	14271	5685
31	NCR ID#	FRCC	230	14018	5584
295	NCR ID#	FRCC	115	27868	5551
294	NCR ID#	FRCC	115	27828	5543
315	NCR ID#	FRCC	230	13810	5502
312	NCR ID#	FRCC	230	12018	4788
51	NCR ID#	FRCC	230	10785	4296
316	NCR ID#	FRCC	230	10616	4229
314	NCR ID#	FRCC	230	10558	4206
320	NCR ID#	FRCC	230	10552	4204
53	NCR ID#	FRCC	230	10342	4120
317	NCR ID#	FRCC	230	10279	4095
302	NCR ID#	FRCC	230	10103	4025
55	NCR ID#	FRCC	230	10076	4014
59	NCR ID#	FRCC	230	9713	3869
304	NCR ID#	FRCC	230	9618	3831
60	NCR ID#	FRCC	230	9605	3826
299	NCR ID#	FRCC	230	9598	3823
303	NCR ID#	FRCC	230	9542	3801
54	NCR ID#	FRCC	230	9110	3629
231	NCR ID#	FRCC	115	14835	2955
215	NCR ID#	FRCC	115	14296	2848
269	NCR ID#	FRCC	115	13212	2632
309	NCR ID#	FRCC	115	12895	2568
230	NCR ID#	FRCC	115	12889	2567
301	NCR ID#	FRCC	115	12781	2546
266	NCR ID#	FRCC	115	12723	2534
238	NCR ID#	FRCC	115	12674	2525
260	NCR ID#	FRCC	115	12674	2525
306	NCR ID#	FRCC	115	11990	2388

271	NCR ID#	FRCC	115	11826	2356
249	NCR ID#	FRCC	115	11049	2201
247	NCR ID#	FRCC	115	10975	2186
246	NCR ID#	FRCC	115	10902	2171
313	NCR ID#	FRCC	115	10868	2165
262	NCR ID#	FRCC	115	10472	2086
242	NCR ID#	FRCC	115	10243	2040
228	NCR ID#	FRCC	115	10089	2010
248	NCR ID#	FRCC	115	9865	1965
217	NCR ID#	FRCC	115	9560	1904
297	NCR ID#	FRCC	115	9521	1896
209	NCR ID#	FRCC	115	9295	1851
243	NCR ID#	FRCC	115	8969	1787
218	NCR ID#	FRCC	115	8926	1778
265	NCR ID#	FRCC	115	8913	1775
232	NCR ID#	FRCC	115	8882	1769
210	NCR ID#	FRCC	115	8875	1768
240	NCR ID#	FRCC	115	8538	1701
239	NCR ID#	FRCC	115	8442	1681
307	NCR ID#	FRCC	115	8397	1673
270	NCR ID#	FRCC	115	8349	1663
272	NCR ID#	FRCC	115	8193	1632
258	NCR ID#	FRCC	115	8000	1593
310	NCR ID#	FRCC	115	7891	1572
211	NCR ID#	FRCC	115	7837	1561
261	NCR ID#	FRCC	115	7822	1558
225	NCR ID#	FRCC	115	7730	1540
234	NCR ID#	FRCC	115	7557	1505
233	NCR ID#	FRCC	115	7543	1502
204	NCR ID#	FRCC	115	7386	1471
259	NCR ID#	FRCC	115	7374	1469
256	NCR ID#	FRCC	115	7314	1457
298	NCR ID#	FRCC	115	7258	1446
244	NCR ID#	FRCC	115	7249	1444
222	NCR ID#	FRCC	115	7204	1435
223	NCR ID#	FRCC	115	7133	1421
263	NCR ID#	FRCC	115	7118	1418
226	NCR ID#	FRCC	115	6989	1392
254	NCR ID#	FRCC	115	6913	1377
267	NCR ID#	FRCC	115	6851	1365
257	NCR ID#	FRCC	115	6846	1364
253	NCR ID#	FRCC	115	6772	1349
245	NCR ID#	FRCC	115	6704	1335
308	NCR ID#	FRCC	115	6571	1309
251	NCR ID#	FRCC	115	6473	1289
241	NCR ID#	FRCC	115	6395	1274

252	NCR ID#	FRCC	115	5556	1107
255	NCR ID#	FRCC	115	5007	997
5	NCR ID#	FRCC	13.2	39503	903
9	NCR ID#	FRCC	13.2	39501	903
13	NCR ID#	FRCC	13.2	39501	903
1	NCR ID#	FRCC	13.2	39492	903
17	NCR ID#	FRCC	13.2	39473	902
6	NCR ID#	FRCC	13.2	39306	899
10	NCR ID#	FRCC	13.2	39304	899
14	NCR ID#	FRCC	13.2	39304	899
2	NCR ID#	FRCC	13.2	39295	898
18	NCR ID#	FRCC	13.2	39276	898
214	NCR ID#	FRCC	115	4498	896
250	NCR ID#	FRCC	115	4329	862
318	NCR ID#	FRCC	13.2	13238	303

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	120	24	12	12	5685	1500
Median Method	64	13	7	6		1500
Zero Busses	24	5	3	2		

Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**
19	NCR ID#	FRCC	230	31120	12397
319	NCR ID#	FRCC	230	23087	9197
52	NCR ID#	FRCC	230	17615	7017
58	NCR ID#	FRCC	230	17039	6788
56	NCR ID#	FRCC	230	16472	6562
23	NCR ID#	FRCC	230	14271	**5685**
31	NCR ID#	FRCC	230	14018	5584
295	NCR ID#	FRCC	115	27868	5551
294	NCR ID#	FRCC	115	27828	5543
315	NCR ID#	FRCC	230	13810	5502
312	NCR ID#	FRCC	230	12018	4788
51	NCR ID#	FRCC	230	10785	4296
316	NCR ID#	FRCC	230	10616	4229
314	NCR ID#	FRCC	230	10558	4206
320	NCR ID#	FRCC	230	10552	4204
53	NCR ID#	FRCC	230	10342	4120
317	NCR ID#	FRCC	230	10279	4095
302	NCR ID#	FRCC	230	10103	4025
55	NCR ID#	FRCC	230	10076	4014
59	NCR ID#	FRCC	230	9713	3869
304	NCR ID#	FRCC	230	9618	3831
60	NCR ID#	FRCC	230	9605	3826
299	NCR ID#	FRCC	230	9598	3823
303	NCR ID#	FRCC	230	9542	3801
54	NCR ID#	FRCC	230	9110	3629
231	NCR ID#	FRCC	115	14835	2955
215	NCR ID#	FRCC	115	14296	2848
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306	NCR ID#	FRCC	115	11990	2388
271	NCR ID#	FRCC	115	11826	2356

249	NCR ID#	FRCC	115	11049	2201
247	NCR ID#	FRCC	115	10975	2186
246	NCR ID#	FRCC	115	10902	2171
313	NCR ID#	FRCC	115	10868	2165
262	NCR ID#	FRCC	115	10472	2086
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217	NCR ID#	FRCC	115	9560	1904
297	NCR ID#	FRCC	115	9521	1896
209	NCR ID#	FRCC	115	9295	1851
243	NCR ID#	FRCC	115	8969	1787
218	NCR ID#	FRCC	115	8926	1778
265	NCR ID#	FRCC	115	8913	1775
232	NCR ID#	FRCC	115	8882	1769
210	NCR ID#	FRCC	115	8875	1768
240	NCR ID#	FRCC	115	8538	1701
239	NCR ID#	FRCC	115	8442	1681
307	NCR ID#	FRCC	115	8397	1673
270	NCR ID#	FRCC	115	8349	1663
272	NCR ID#	FRCC	115	8193	1632
258	NCR ID#	FRCC	115	8000	1593
310	NCR ID#	FRCC	115	7891	1572
211	NCR ID#	FRCC	115	7837	1561
261	NCR ID#	FRCC	115	7822	1558
225	NCR ID#	FRCC	115	7730	1540
234	NCR ID#	FRCC	115	7557	1505
233	NCR ID#	FRCC	115	7543	1502

Implementation Plan

Project 2007-11 Disturbance Monitoring

Requested Approvals

- PRC-002-2 Disturbance Monitoring and Reporting Requirements

Requested Retirements

- PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements
- PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting

Prerequisite Approvals

- None

Applicable Entities

- Planning Coordinator
- Reliability Coordinator
- Transmission Owner
- Generator Owner

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan reflects consideration of the following:

1. This standard reflects the need for data, rather than equipment, with the understanding that the data is collected from Disturbance Monitoring Equipment distributed across the BES.
2. A significant amount of sequence of events recording (SER), fault recording (FR), and dynamic disturbance recording (DDR) capability already exists on the BES. The monitoring requirements in this standard align with industry practices. Therefore, many existing recordings can satisfy the Requirements and Implementation Plan put forth.
3. Fault MVA data is readily available or calculable by the Transmission Owners for the BES buses they own. Therefore, six (6) months is adequate time for generating the list of BES bus locations following the methodology described in Attachment 1 (Requirement R1).

4. Responsible Entities have the relevant data and information pertaining to the BES Elements requiring DDR and six (6) months is adequate time for working with any affected entities and generating the list of BES Elements.
5. The nine (9) month time period for R12 includes the six (6) month implementation for R1 and R5, and a three (3) month additional time period to make notifications. The nine (9) months for R12 implementation is reasonable for the contents of that requirement.
6. A total percentage (%) of BES buses and BES Elements established in Requirements R1 and R5 respectively, are used in the Implementation Plan since these lists are explicitly created and readily available. It is expected that many monitoring requirements will become compliant with incremental changes to recording capability.
7. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the Entities.
8. Implementation of disturbance monitoring recording following changes to the system are addressed by following reassessment of the lists as per Requirement R1 and Requirement R5.
9. Implementing SER, FR, and DDR capability may require scheduled outages for both Transmission Owners and Generator Owners. Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant. Meanwhile, Transmission Owners probably will have more BES Elements requiring SER, FR, and DDR and may have to schedule outages across the system. The Implementation Plan takes scheduling outages into account.
10. An Entity owning only one (1) identified BES bus, BES Element, or generating unit is allowed six (6) years for implementation to accommodate normal outage schedules.
11. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective Entities.

General Considerations

Each Transmission Owner and Generator Owner subject to PRC-018-1 shall maintain the ability to provide Disturbance monitoring data using current methods required by PRC_018-1 until the entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. As required in PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting, Requirement R1, Parts 1.1 and 1.2, it is expected that the Transmission Owner and Generator Owner will have those functionalities with regard to their current Disturbance data.

Effective Date

The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard(s) for Retirement

PRC-002-1 Midnight of the day immediately prior to the Effective Date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Each Transmission Owner, and Generator Owner shall maintain documentation to demonstrate compliance with PRC-018-1 until that entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2 and shall be applicable to an entity's Disturbance Monitoring and Reporting activities not yet transitioned to PRC-002-2. PRC-018-1 will be retired following full implementation of PRC-002-2 as noted below.

PRC-018-1 Midnight of the day immediately prior to six (6) years after the Effective Date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for PRC-002-2 Requirements R1 and R5:

Entities shall be 100% compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirement R12:

Entities shall be 100% compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:

Entities shall be at least 50% compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date.

Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the Effective Date.

Entities shall be 100% compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list.

Conforming Changes to Other Standards

Where conflicts between the continent-wide standard PRC-002-2 and a regional standard exist, entities should comply with PRC-002-2. Conflicts will be addressed in the regional standards development process.

- The following conflicts PRC-002-2 Requirement R3 stipulates data must be captured by fault recording to determine electrical quantities. PRC-002-NPCC-01 Requirement R3 stipulates the recording of those quantities.
- PRC-002-2 Requirement R5 stipulates the capture of dynamic disturbance recording data for HVDC. PRC-002-NPCC-01 does specify HVDC.
- PRC-002-2 Requirement R8 recognizes dynamic disturbance recording that is not continuous. PRC-002-NPCC-01 addresses dynamic disturbance recorders installed after the standard was approved have to be continuous.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-11 Disturbance Monitoring

Requested Approvals
- PRC-002-2 Disturbance Monitoring and Reporting Requirements

Requested Retirements
- PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements
- PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting

Prerequisite Approvals
- None

Applicable Entities
- Planning Coordinator
- Reliability Coordinator
- Transmission Owner
- Generator Owner

Revisions to Defined Terms in the NERC Glossary

~~The standard drafting team proposes the following new definitions:~~	
~~Dynamic Disturbance Recording (DDR)~~	~~The recording of time sequenced data for dynamic power system characteristics such as power swings, frequency variations, and abnormal voltage problems.~~
~~Fault Recording (FR)~~	~~The recording of time sequenced waveform data for short circuits or failure of Elements resulting in abnormal voltage(s) and /or current(s).~~
~~Sequence of Events Recording (SOER)~~	~~The recording of time sequenced data for change in status of Elements, which may include protection and control devices.~~

Background

The Implementation Plan reflects consideration of the following:

1. This standard reflects the need for data, rather than equipment, with the understanding that the data is collected from Disturbance Monitoring Equipment distributed across the BES~~system~~.
2. A significant amount of s~~S~~equence of ~~E~~events ~~R~~recording (SER), f~~F~~ault r~~R~~ecording (FR), and d~~D~~ynamic d~~D~~isturbance r~~R~~ecording (DDR) equipment already exists on the BES. The monitoring~~location~~ requirements in this standard align with industry practices~~ for locating this equipment~~. Therefore, many existing recordings can~~-~~ satisfy the Requirements and Implementation Plan put forth.
3. Fault MVA data is readily available or calculable by the Transmission Owners for the BES buses ~~locations~~ they own. Therefore, six (6) months is adequate time for generating the list of BES bus locations following the methodology described in Attachment 1 (Requirement R1).
4. Responsible Entities have the relevant data and information pertaining to the BES Elements requiring DDR~~ynamic Disturbance Recording~~ and six (6) months is adequate time for working with any affected Entities and generating the list of BES Elements.
5. The nine (9) month time period for ~~R2, R7, and ~~R12~~4~~ includes the six (6) month implementation for R1, and R5~~6~~ ~~(refer to 3, and 4 preceding), and a three (3) month additional time period to make notifications.~~ The nine (9) months for R12~~4~~ implementation is reasonable for the contents of that requirement. ~~All requirements pertaining to possible implementation of equipment are referenced to notification of the list of bus locations or Elements to account for any delays in the process of location and Element selection.~~
6. A total percentage (%) of BES buses~~ locations~~ and BES Elements established in Requirements R1 and R5~~6~~ respectively, are used in the Implementation Plan since these lists are explicitly created and readily available. It is expected that many locations will become compliant with incremental changes to recording.
7. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the Entities. ~~The timelines put forth allow for inertial delays in implementing new equipment or technologies (e.g. developing new standards and processes, testing and energization, and project management).~~
8. Implementation of disturbance monitoring following changes to the system are addressed ~~by referencing the Implementation Plan to the time of notification following reassessment. Changes to disturbance monitoring are only required for identified bus locations or Elements ~~following reassessment of the lists as per Requirement R1~~, Part 1.2~~ and Requirement R5~~6, Part 6.2~~.

9. Implementing SOER, FR, and DDR may require scheduled outages for both Transmission Owners and Generator Owners. Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant. Meanwhile, Transmission Owners will have more Elements requiring SOER, FR, and DDR and may have to schedule outages across the system. The Implementation Plan takes this into account for scheduling outages.
10. An Entity owning only one (1) identified bus location, Element, or generating unit is allowed four (4) years for implementation to accommodate normal outage schedules.
11. The Implementation Plan accounts for any increase in requests to vendors for this technology or equipment that could impact implementation timelines for the respective Entities.

General Considerations

Each Transmission Owner and Generator Owner shall maintain the ability to provide Disturbance Monitoring data using current methods until the entity meets the requirements of PRC-002-2 in accordance with this Implementation plan. As required in PRC-018-1 Disturbance Monitoring Equipment Installed and Data Reporting, Requirement R1, Parts 1.1 and 1.2, it is expected that the Transmission Owner and Generator Owner will have those functionalities in regards to their current Disturbance Data.

Effective Date

The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard(s) for Retirement

PRC-002-1 Midnight of the day immediately prior to the Effective Date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Each Transmission Owner, and Generator Owner shall maintain documentation to demonstrate compliance with PRC-018-1 until that entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2 and shall be applicable to an entity's Disturbance Monitoring and Reporting activities not yet transitioned to PRC-002-2. PRC-018-1 will be retired following full implementation of PRC-002-2 as noted below.

PRC-018-1 Midnight of the day immediately prior to six (6) years after the Effective Date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

~~**Implementation Plan for Definitions**~~
~~Entities shall use these definitions when implementing any requirement in this standard that references one of the definitions.~~

Implementation Plan for PRC-002-2 Requirements R1 and R5~~6~~:
Entities shall be 100% compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirement~~s R2, R7, and~~ R12~~4~~:
Entities shall be 100% compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) -months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R5, R6~~8~~, R7~~9~~, R8~~10~~, R9~~11~~, R10~~12~~ and R11~~3~~:
Entities shall be at least 50% compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date.

Entities that own only one (1) identified BES bus , BES Element, or generating unit shall be fully compliant within six (6) years of the Effective Date.

~~Entities shall be compliant with the initial list of BES bus locations in Requirement R1 and list of Elements in Requirement R6 within the following:~~

- ~~Following governmental authority or as otherwise provided for in jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect,~~
    - ~~At least 25% compliant within two (2) years following notification of the list~~
    - ~~At least 50% compliant within three (3) years following notification of the list~~

- ~~100% compliant within four (4) years following notification of the list~~
- ~~**Note**: Entities that own only one (1) identified BES bus location, Element, or generating unit shall be 100% compliant within four (4) years following notification of the list.~~

- ~~Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is forty-eight (48) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction,~~

Entities shall be 100% compliant with a reassessed list from Requirement R1~~, Part 1.2~~ or R5~~6, Part~~ 5~~6.2~~ within three (3) years following notification of the list.

Conforming Changes to Other Standards

Where conflicts between the continent-wide standard PRC-002-2 and a regional standard exist, entities should comply with PRC-002-2. Conflicts will be addressed in the regional standards development process.

- The following conflicts PRC-002-2 Requirement R3 stipulates data must be captured by fault recording to determine electrical quantities. PRC-002-NPCC-01 Requirement R3 stipulates the recording of those quantities.
- PRC-002-2 Requirement R5 stipulates the capture of dynamic disturbance recording data for HVDC. PRC-002-NPCC-01 does specify HVDC.

PRC-002-2 Requirement R8 recognizes dynamic disturbance recording that is not continuous. PRC-002-NPCC-01 addresses dynamic disturbance recorders installed after the standard was approved have to be continuous.

Implementation Plan Summary											
Requirement	Entity	Identify bus locations/ Elements	Notification	SOE	FR	DDR	Time Sync	5 Year Assessment	Other	Percent Compliant	Following compliance instructions noted for each requirement above:
R1	TO	X	X	X	X			X		100	Six (6) months
R2	TO		X							100	Nine (9) months
R23	TO/GO			X						25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R34	TO/GO				X					25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R45	TO/GO				X					25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R56	RE (PC or RC)	X	X			X		X		100	Six (6) months
R7	RE (PC or RC)		X							100	Nine (9) months
R68	RE (PC or RC)TO					X				25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R79	TGO					X				25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R810	TO/GO					X				25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R911	TO/GO					X				25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R102	TO/GO						X			25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R113	TO/GO								X	25	Two (2) years
										50	Three (3) years
										100	Four (4) years
R124	TO/GO								X	100	Nine (9) months

Unofficial Comment Form

Project 2007-11 Disturbance Monitoring

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on **PRC-002-2 - Disturbance Monitoring and Reporting Requirements**. The electronic comment form must be completed by **8 p.m. Eastern on Monday, June 23, 2014**.

If you have questions please contact Stephen Crutchfield via email or by telephone at 609-651-9455.

Click here for the Project Page.

Background Information

Project 2007-11 Disturbance Monitoring was initiated to replace the existing fill-in-the-blank Standard PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements with a more comprehensive standard. (Fill-in-the-blank standards are those standards that depend on regional criteria or procedures not currently contained within certain Reliability Standards, but which are needed to provide additional requirements for implementing the standards within the Regions.) The Disturbance Monitoring Standard Drafting Team (DMSDT) posted a draft standard for a 45-day comment/ballot period November 1- December 16, 2013. Based on the comments received from stakeholders, the DMSDT has revised the standard. The revisions to the standard are summarized in the paragraphs below.

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

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

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

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

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

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

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

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

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

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

- Added language to the Guidelines and Technical Basis section of the standard.

***Please use the electronic comment form to submit your final comments to NERC.**

Questions

You do not have to answer all questions. Enter all comments in simple text format. Bullets, numbers, and special formatting will not be retained. Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. The DMSDT merged the notification requirement of Requirement R2 into Requirement R1. The DMSDT also merged notification requirement of Requirement R7 into Requirement R6 (new R5). Do you support these new requirements? If not, please explain why and provide suggested changes.

☐ Yes
☐ No
Comments:

2. The DMSDT revised the requirements for dynamic disturbance recording data based on stakeholder comments. Do you agree with the BES Elements requiring dynamic disturbance recording data listed in Requirement R5? If not, please provide technical justification.

☐ Yes
☐ No
Comments:

3. If you have any other comments that you haven’t already mentioned above, please provide them here:
Comments:

A. Introduction

1. **Title:** **Define Regional Disturbance Monitoring and Reporting Requirements**
2. **Number:** PRC-002-1
3. **Purpose:** Ensure that Regional Reliability Organizations establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of Disturbance data to facilitate analyses of events and verify system models.
4. **Applicability**
   - **4.1.** Regional Reliability Organization.
5. **Effective Date:** Nine months after BOT adoption.

B. Requirements

R1. The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:

R1.1. Location, monitoring and recording requirements, including the following:

R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R1.1.2. Devices to be monitored.

R2. The Regional Reliability Organization shall establish the following installation requirements for fault recording:

R2.1. Location, monitoring and recording requirements, including the following:

R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R2.1.2. Elements to be monitored at each location.

R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R2.1.3.1. Three phase to neutral voltages.

R2.1.3.2. Three phase currents and neutral currents.

R2.1.3.3. Polarizing currents and voltages, if used.

R2.1.3.4. Frequency.

R2.1.3.5. Megawatts and megavars.

R2.2. Technical requirements, including the following:

R2.2.1. Recording duration requirements.

R2.2.2. Minimum sampling rate of 16 samples per cycle.

R2.2.3. Event triggering requirements.

R3. The Regional Reliability Organization shall establish the following installation requirements for dynamic Disturbance recording:

R3.1. Location, monitoring and recording requirements including the following:

R3.1.1. Criteria for equipment location giving consideration to the following:

- Site(s) in or near major load centers
- Site(s) in or near major generation clusters
- Site(s) in or near major voltage sensitive areas
- Site(s) on both sides of major transmission interfaces
- A major transmission junction
- Elements associated with Interconnection Reliability Operating Limits
- Major EHV interconnections between control areas
- Coordination with neighboring regions within the interconnection

R3.1.2. Elements and number of phases to be monitored at each location.

R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R3.1.3.1. Voltage, current and frequency.

R3.1.3.2. Megawatts and megavars.

R3.2. Technical requirements, including the following:

R3.2.1. Capability for continuous recording for devices installed after January 1, 2009.

R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.

R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following:

R4.1. Criteria for events that require the collection of data from DMEs.

R4.2. List of entities that must be provided with recorded Disturbance data.

R4.3. Timetable for response to data request.

R4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE[1] analysis tool,

R4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files[2].

R4.6. Data content requirements and guidelines.

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[1] IEEE C37.111-1999 IEEE Standard Common Format for Transient Data Exchange for Power Systems or its successor standard

[2] Compliance with this requirement is not effective until the IEEE Standard is approved.

R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.

R6. The Regional Reliability Organization shall periodically (at least every five years) review, update and approve its Regional requirements for Disturbance monitoring and reporting.

C. Measures

M1. The Regional Reliability Organization's requirements for the installation of Disturbance Monitoring Equipment shall address Requirements 1 through 3.

M2. The Regional Reliability Organization's Disturbance monitoring data reporting requirements shall include all elements identified in Requirements 4.

M3. The Regional Reliability Organization shall have evidence it provided its Regional Disturbance monitoring and reporting requirements as required in Requirement 5.

M4. The Regional Reliability Organization shall have evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its DME requirements for three years.

The Compliance Monitor will retain its audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through providing its documentation of Disturbance Monitoring and Reporting requirements or self-certification as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exist:

2.1.1 Disturbance data reporting requirements were not specified as required in R4.1 through R4.6.

2.1.2 No evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in R6.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions exist:

2.2.1 Technical requirements were not specified for one or more types of DMEs.

2.2.2 Requirements do not provide criteria for equipment location or criteria for monitored elements or monitored quantities as required R1, R2 and R3.

2.3. Level 3: Not applicable.

2.4. Level 4: Disturbance monitoring and reporting requirements were not available or were not provided to Transmission Owners and Generator Owners.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Disturbance Monitoring Equipment Installation and Data Reporting**

2. **Number:** PRC-018-1

3. **Purpose:** Ensure that Disturbance Monitoring Equipment (DME) is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

5. **Effective Dates:** Phased in over four years after BOT adoption:

   Requirements 1 and 2:

   – 50% compliant two years after initial issuance of regional requirements per RELIABILITY STANDARD PRC-002 Requirement 5.

   – 75% compliant three years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   – 100% compliant four years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   Requirements 3 through 6:

   – 100% compliant six months after BOT adoption for already installed DME.

   – 100% compliant six months after installation for DMEs installed to meet Regional Reliability Organization requirements per reliability standard PRC-002 Requirements 1, 2 and 3.

B. Requirements

R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:

R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)

R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days..

R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).

R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):

R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).

R3.2. Make and model of equipment.

R3.3. Installation location.

R3.4. Operational status.

R3.5. Date last tested.

R3.6. Monitored elements, such as transmission circuit, bus section, etc.

R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc.

R3.8. Monitored electrical quantities, such as voltage, current, etc.

R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).

R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.

R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:

R6.1. Maintenance and testing intervals and their basis.

R6.2. Summary of maintenance and testing procedures.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have evidence that DMEs it is required to have meet the functional requirements specified in Requirement 1 and are installed in accordance with its associated Regional Reliability Organization's requirements (R2).

M2. The Transmission Owner and Generator Owner shall each maintain the data listed in Requirements 3.1 through 3.8 for the DMEs installed to meet its Regional Reliability Organization's DME installation requirements.

M2.1 The Transmission Owner and Generator Owner shall each have evidence it provided this DME data to its Regional Reliability Organization within 30 calendar days of a request.

M3. The Transmission Owner and Generator Owner shall each have evidence it retained and provided recorded Disturbance data to entities in accordance with its associated Regional Reliability Organization's Disturbance data reporting requirements. (R4 R5)

M4. Each Transmission Owner and Generator Owner that is required to install DMEs to meet its Regional Reliability Organization's DME installation requirements, shall have an associated DME maintenance and testing program as defined in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each retain any Disturbance data provided to the Regional Reliability Organization (Requirement 4) for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions is present:

2.1.1 DMEs that meet all the Regional Reliability Organization's installation requirements (in accordance with Requirement 2) were installed at 90% or more but not all of the required locations.

2.1.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with Requirement 4) was provided for 90% or more but not all of the required locations.

2.1.3 Data on required DMEs was incomplete (in accordance with R3)

2.1.4 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 80% or more but less than 90% of the required locations.

2.2.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 80% or more but less than 90% of the required locations.

2.2.3 Recorded Disturbance data was not provided to all required entities (in accordance with R4)

2.2.4 Archived data was not retained for three years (in accordance with Requirement 5).

2.2.5 Documentation of the DME maintenance and testing program provided was complete as required in R6, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions is present:

2.3.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 70% or more but less than 80% of the required locations.

2.3.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 70% or more but less than 80% of the required locations.

2.3.3 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. Level 4: There shall be a level four non-compliance if any one of the following conditions is present:

2.4.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at less than 70% of the required locations.

2.4.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for less than 70% of the required locations.

2.4.3 DMEs that meet all functional requirements (in accordance with R1) were not installed at all required locations.

2.4.4 Documentation of the DME maintenance and testing program was not provided, or no evidence that the testing program did occur within the identified intervals

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Consideration of Issues and Directives

Project 2007-11 Disturbance Monitoring
PRC-002-2 Disturbance Monitoring and Reporting Requirements

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"For the reasons stated in the NOPR, the Commission will not approve or remand PRC-002-1." "We agree with [American Public Power Association], Alcoa and Otter Tail that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards. Consistent with that goal, the Commission directs the ERO to consider APPA, Alcoa and Otter Tail's suggestions in the Reliability Standards development process as it modifies PRC-002-1 to provide missing information needed for the Commission to act on this Reliability Standard." (see below for American Public Power Association, Alcoa, and Otter Tail discussion)	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1455-56	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances. The use of recording and specifying recording data parameters, greater consistency is achieved in PRC-002-2.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in addressing the completion of this Reliability Standard."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1452	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances.
"Alcoa suggests that the ERO—instead of a Regional Entity—should define the requirements for DME and the type of report it generates. The requirements and equipment specifications should be consistent throughout North America. In addition, Alcoa suggests that the criteria for installation of such equipment should include the necessary monitoring and recording that contribute to analysis and enhance reliability."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1453	Determines the key locations for which Disturbance data must be recorded which eliminates the need for equipment requirements. PRC-002-2 specifies the storage requirements and recording format for the collected data to ensure continent-wide uniformity to expedite event analysis.
"Otter Tail suggests that PRC-002-1 should be developed on an Interconnection wide basis to ensure consistency and promote reliability of the Bulk-Power System."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards	PRC-002-2 will apply on a continent-wide basis.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
	for the Bulk-Power System (Issued March 16, 2007); Paragraph 1454	
"The Commission requires supplemental information for any Reliability Standard that currently requires a regional reliability organization to fill in missing criteria or procedures. Where important information has not yet been provided to us to enable us to complete our review, we are not in a position to approve or remand those Reliability Standards. Accordingly, we will not approve or remand such Reliability Standards until the ERO submits further information. Until such information is provided, compliance with fill-in-the-blank standards should continue on a voluntary basis, and the Commission considers compliance with such Reliability Standards to be a matter of good utility practice."	Fill-in-the-blank Consideration FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 297.	By addressing recording instead of equipment, the Drafting Team has produced a continent-wide standard to have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.

Project 2007-11 – Disturbance Monitoring
PRC-002-2 – Disturbance Monitoring and Reporting Requirements

Mapping Document for PRC-018-1 to PRC-002-2 and PRC-002-1 to PRC-002-2

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that arise from the inherent differences between regional power systems. PRC-018-1 and PRC-002-1 deal with equipment, PRC-002-2 deals with recording. By specifying recording instead of equipment, PRC-002-2 governs the practical capturing of abnormal event data on the BES.

PRC-018-1 Requirements reference PRC-002-1 which requires PRC-018-1 Requirements to be either retired or covered in PRC-002-2.

As used herein, the acronym SER is Sequence of Events Recording, the acronym FR is Fault Recording, and the acronym DDR is Dynamic Disturbance Recording.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard **PRC-002 Requirements 1-3**) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to **within 2 milliseconds** or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be **retrievable for ten calendar days**.	**R10**. Each Transmission Owner and Generator Owner shall time synchronize all SER, FR and DDR data for the BES bus buses identified per Requirement R1 and BES Elements identified per Requirement R5 to within ± 2 milliseconds of Coordinated Universal Time (UTC), time stamped with or without a local time offset. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic C37.111, (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

<table>
<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td colspan="2">Notes: PRC-018-1, Requirement R1 is covered in PRC-002-2, Requirements R10 and R11.
PRC-018-1 addresses the equipment used for Disturbance monitoring data recording, PRC-002-2 addresses the recorded data. Technological advances made in the types of equipment used to record power system data have made it more effective to direct PRC-002-2 at the recording, not the equipment. Time synchronization and having the data retrievable for 10 days are general parameters that facilitate data analysis. PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirement R11.</td></tr>
<tr><td>R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization’s installation requirements (reliability standard PRC-002 Requirements 1 through 3).

PRC-002-1
R1. The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:
R1.1. Location, monitoring and recording requirements, including the following:
R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).
R1.1.2. Devices to be monitored
R2. The Regional Reliability Organization</td><td>R1. Each Transmission Owner shall identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

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

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities at the BES Elements they own connected to the BES buses identified per Requirement R1: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

3.1 Phase-to-neutral voltages for each phase of each specified line or BES bus.</td></tr>
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Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
shall establish the following installation requirements for **fault recording**: R2.1.Location, monitoring and recording requirements, including the following: R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars. R2.2.Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements. R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**:	3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1. Transformers that have a low-side operating voltage of 100kV or above. 3.2.2. Transmission lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 30 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault as seen by the fault recorder. **4.2.** A minimum recording rate of 16 samples per cycle. **4.3.** Trigger settings for at least the following: **4.3.1.** Neutral (residual) overcurrent. **4.3.2.** Phase undervoltage or overcurrent. R5. Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder (DDR) data is required, notify within 90 calendar days other owners, if any, of Elements connected to

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R3.1. Location, monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after	those BES buses that those Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1.** The BES Elements shall include the following: **5.1.1.** Generating resource(s) with: **5.1.1.1.** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA. **5.1.2.** Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines: • Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection or • Transfer Paths in the Western Interconnection Path Rating Catalog or • Voltage stability limited transfer paths or load serving area or • Interfaces between Balancing Authority Areas or • Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC) **5.1.3.** Each terminal of a high-voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA on the alternating

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	current (AC) portion of the converter. **5.1.4.** One or more BES Elements associated with Interconnection Reliability Operating Limits. **5.1.5.** Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program. **5.2.** The BES Elements shall include a minimum of: **5**.2.1 One BES Element **5**.2.2 One additional BES Element per each additional 3,000 MW of its historical peak system Demand. R6. Each Transmission Owner shall have DDR data for each BES Element they own as per Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	R7. Each Generator Owner shall have DDR data for each BES Element they own as per Requirement R5, to determine the following electrical quantities: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up (GSU) transformer high-side or low-side voltage level. 7.2. The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. Each Transmission Owner and Generator Owner that is responsible for DDR data as per Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	8.2. At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	R9. Each Transmission Owner and Generator Owner shall have DDR data, for the Elements as per Requirement R5, which conform to the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-018-1, Requirement R2 and PRC-002-1 Requirements R1-R3 are covered in PRC-002-2, Requirements R1-R9. PRC-018-1, Requirement R2 references PRC-002-1 Requirements R1-R2. PRC-002-1, Requirements R1-R3 reference equipment installation requirements for FR, SER, and DDR. The technical parameters of PRC-002-2 pertain to the characteristics and content of the recordings that are needed to facilitate event analysis.	
R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder,	None.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc. R3.8.Monitored electrical quantities, such as voltage, current, etc.	
Notes: PRC-018-1, Requirement R3 is not covered in PRC-002-2. PRC-018-1 Requirement R3 refers to equipment and therefore is not mapped to PRC-002-2 which deals with recorded data and not equipment.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R4. The Transmission Owner and Generator Owner shall each **provide Disturbance data** (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard **PRC-002 Requirement 4**). **PRC-002-1** R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool.	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic C37.111, (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
Notes: PRC-018-1, Requirement R4 references PRC-002-1 Requirement R4 which is covered is PRC-002-2, Requirement R11.	
R5. The Transmission Owner and Generator Owner shall each **archive all data** recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	Covered in the Compliance section **1.2 Evidence Retention** The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation: The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years. The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years. The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years. The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11,

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	and M12 for three calendar years. The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years. If a Transmission Owner, Generator Owner, or Responsible Entity (Planning Coordinator or Reliability Coordinator) is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.
Notes: PRC-018-1, Requirement R5 is covered in the PRC-002-2 Compliance section under Evidence Retention.	
R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes: R6.1. Maintenance and testing	**R12.** Each Transmission Owner and Generator Owner, within 90 calendar days of the discovery of a failure of the SER and FR data at the BES buses identified per Requirement R1 or DDR data for the BES Elements identified per Requirement R5, shall restore the recording capability or develop a Corrective Action Plan (CAP), to be submitted to the Regional Entity, to restore the recording ability which includes a timeline for the restoration.: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
intervals and their basis. R6.2. Summary of maintenance and testing procedures.	
Notes: PRC-018-1, Requirement R6 is covered in PRC-002-2, Requirement R12. PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R12 deals with the long term availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability.	

Standard PRC-002-1	Proposed Standard PRC-002-2
R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event recording**: R1.1. Location, monitoring and recording requirements, including the following: R1.1.1. Criteria for equipment location (e.g.,	**R1.** Each Transmission Owner shall identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker they own connected directly to the BES buses identified per Requirement R1 and associated with the BES Elements at those BES buses identified per Requirement R1. [Violation Risk Factor: Lower] [Time Horizon:

Standard PRC-002-1	Proposed Standard PRC-002-2
by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored	Long-term Planning]
Notes: PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirements R1-R2. (See PRC-018-1, Requirement R3 above for additional information.)	
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1. Location , monitoring and recording requirements, including the following: R2.1.1. Criteria for equipment location (e.g.,	**R1.** Each Transmission Owner shall identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities at the BES Elements they own connected to the BES buses

Standard PRC-002-1	Proposed Standard PRC-002-2
by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars.	identified per Requirement R1: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 3.1 Phase-to-neutral voltages for each phase of each specified line or BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1. Transformers that have a low-side operating voltage of 100kV or above. 3.2.2. Transmission lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a post-trigger record length of at least 30 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault as seen by the fault recorder. **4.2.** A minimum recording rate of 16 samples per cycle. **4.3.** Trigger settings for at least the following: **4.3.1.** Neutral (residual) overcurrent. **4.3.2.** Phase undervoltage or overcurrent.

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.2. Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements.	
Notes: PRC-002-1, Requirement R2 is covered in PRC-002-2, Requirements R1, R2, R4, and R5.	
R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**: R3.1. Location , monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving consideration to the following:	**R5.** Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder (DDR) data is required, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1.** The BES Elements shall include the following: **5.1.1.** Generating resource(s) with: **5.1.1.1.** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA.

Standard PRC-002-1	Proposed Standard PRC-002-2
-Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R3.1.3.1. Voltage, current	**5.1.2.** Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines: • Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection or • Transfer Paths in the Western Interconnection Path Rating Catalog or • Voltage stability limited transfer paths or load serving area or • Interfaces between Balancing Authority Areas or • Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC) **5.1.3.** Each terminal of a high-voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA on the alternating current (AC) portion of the converter. **5.1.4.** One or more BES Elements associated with Interconnection Reliability Operating Limits. **5.1.5**. Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program. **5.2.** The BES Elements shall include a minimum of: **5**.2.1 One BES Element **5**.2.2 One additional BES Element per each additional 3,000 MW of its historical peak system Demand.

Standard PRC-002-1	Proposed Standard PRC-002-2
and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	**R6.** Each Transmission Owner shall have DDR data for each BES Element they own as per Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. **R8.** Each Transmission Owner and Generator Owner that is responsible for DDR data as per Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz

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	o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds R9. Each Transmission Owner and Generator Owner shall have DDR data, for the Elements as per Requirement R5, which conform to the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-002-1, Requirement R3 is covered in PRC-002-2, Requirements R5-R6 and R8-R9.	
R4. The Regional Reliability Organization shall establish requirements for facility owners	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC:

Standard PRC-002-1	Proposed Standard PRC-002-2
to **report Disturbance data recorded** by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool, 4.5. Naming of data files in conformance with the IEEE	*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic C37.111, (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

Standard PRC-002-1	Proposed Standard PRC-002-2
C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	
Notes: PRC-002-1, Requirement R4 is covered in PRC-002-2, Requirement R13.	
R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.	**R1.** Each Transmission Owner shall identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R5.** Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder (DDR) data is required, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1.** The BES Elements shall include the following: **5.1.1.** Generating resource(s) with: **5.1.1.1.** Gross individual nameplate rating greater than or equal to 500

Standard PRC-002-1	Proposed Standard PRC-002-2
	MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA. **5.1.2.** Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines: • Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection or • Transfer Paths in the Western Interconnection Path Rating Catalog or • Voltage stability limited transfer paths or load serving area or • Interfaces between Balancing Authority Areas or • Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC) **5.1.3.** Each terminal of a high-voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA on the alternating current (AC) portion of the converter. **5.1.4.** One or more BES Elements associated with Interconnection Reliability Operating Limits. **5.1.5**. Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program. **5.2**. The BES Elements shall include a minimum of:

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.2.1 One BES Element **5**.2.2 One additional BES Element per each additional 3,000 MW of its historical peak system Demand.
Notes: PRC-002-1, Requirement R5 is covered in PRC-002-2, Requirements R2, R6-R7.	
R6. The Regional Reliability Organization shall periodically (**at least every five years**) review, update and approve its Regional requirements for Disturbance monitoring and reporting.	**R1.** Each Transmission Owner shall identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R5.** Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder (DDR) data is required, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1.** The BES Elements shall include the following: **5.1.1.** Generating resource(s) with: **5.1.1.1.** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300

Standard PRC-002-1	Proposed Standard PRC-002-2
	MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA. **5.1.2.** Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines: • Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection or • Transfer Paths in the Western Interconnection Path Rating Catalog or • Voltage stability limited transfer paths or load serving area or • Interfaces between Balancing Authority Areas or • Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC) **5.1.3.** Each terminal of a high-voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA on the alternating current (AC) portion of the converter. **5.1.4.** One or more BES Elements associated with Interconnection Reliability Operating Limits. **5.1.5**. Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program. **5.2**. The BES Elements shall include a minimum of: **5**.2.1 One BES Element **5**.2.2 One additional BES Element per each additional 3,000 MW of its

Standard PRC-002-1	Proposed Standard PRC-002-2
	historical peak system Demand.
Notes: PRC-002-1, Requirement R6 is covered in PRC-002-2, Requirements R1 and R5.	

Project 2007-11 Disturbance Monitoring

VRF and VSL Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-002-2 – Disturbance Monitoring and Reporting Requirements.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines.

The Disturbance Monitoring and Reporting Requirements Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria –VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed VRF	**Lower**
NERC VRF Discussion	R1 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 establishes the list of Sequence of Events Recordings and Fault Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for establishing a list of BES bus locations for Sequence of Events Recording and Fault Recording using the selection procedure in Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish the list of BES bus locations for Sequence of Events Recording and Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to establish a list of BES bus locations for Sequence of Events Recording and Fault Recording and to review the list every 5 calendar years. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Lower VSL	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 80% but less than 100% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by 10 calendar days or less.
Proposed Moderate VSL	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 70% but less than or equal to 80% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by greater than 10 calendar days but less than or equal to 20 calendar days.
Proposed High VSL	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 60% but less than or equal to 70% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by greater than 20 calendar days but less than or equal to 30 calendar days.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Severe VSL	The Transmission Owner identified the BES buses as directed by Requirement R1for less than or equal to 60% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying one or more other owners by greater than 30 calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 provides criteria for Sequence of Events Recording which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Sequence of Events Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Sequence of Events Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to establish criteria for Sequence of Events Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 75% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Moderate VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 50% but less than or equal to 75% of the total SER

VRF and VSL Justifications – PRC-002-2, R2	
	data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed High VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 10% but less than or equal to 50% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Severe VSL	Each Transmission or Generator Owner as directed by Requirement R2 had from 0% but less than or equal to 10% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R3	
Proposed VRF	**Lower**
NERC VRF Discussion	R3 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 75% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 50% but less than or equal to 75% of the total set of required electrical quantities, which is the product of the total number of monitored BES

VRF and VSL Justifications – PRC-002-2, R3	
	Elements and the number of specified electrical quantities per each Element.
Proposed High VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 10% but less than or equal to 50% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 0% but less than or equal to 10% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R4	
Proposed VRF	**Lower**
NERC VRF Discussion	R4 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recordings selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R4.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R4.

VRF and VSL Justifications – PRC-002-2, R4	
Proposed High VSL	The Transmission Owner or Generator Owner had FR data that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R4.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data that meets more than 0% but less than or equal to 10% of the total recording properties as specified in Requirement R4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-002-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 establishes the list of Dynamic Disturbance Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for identifying BES Elements for Dynamic Disturbance Recording. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to identify BES Elements for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective which identifies BES Elements within specified criteria and to review the list every 5 calendar years. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R5 for more than 80% but less than 100% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R5 but was late by 30 calendar days or less.

VRF and VSL Justifications – PRC-002-2, R5	
	OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by 10 calendar days or less.
Proposed Moderate VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R5 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.
Proposed High VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R5 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.
Proposed Severe VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R5 for less than or equal to 60% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R5 but was late by greater than 90 calendar days. OR

VRF and VSL Justifications – PRC-002-2, R5	
	The Responsible Entity as directed by Requirement R5 was late in notifying one or more owners by greater than 30 calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VRF and VSL Justifications – PRC-002-2, R5	
A Cumulative Number of Violations	
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 50% but less than or equal to

VRF and VSL Justifications – PRC-002-2, R6	
	75% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-002-2, R6	
Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R7	
Proposed VRF	**Lower**
NERC VRF Discussion	R7 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 50% but less than or equal to 75%

VRF and VSL Justifications – PRC-002-2, R7	
	of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-002-2, R7	
Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R8	
Proposed VRF	**Lower**
NERC VRF Discussion	R8 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes the need for continuous data recording and storage for Dynamic Disturbance Recordings established in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 75% but less than 100% of the Elements they own as determined in Requirement R5.

VRF and VSL Justifications – PRC-002-2, R8	
Proposed Moderate VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 50% but less than or equal to 75% of the Elements they own as determined in Requirement R5.
Proposed High VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 0% but less than or equal to 50% of the Elements they own as determined in Requirement R5.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the Elements they own as determined in Requirement R5.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R8	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R9	
Proposed VRF	**Lower**
NERC VRF Discussion	R9 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement established technical specifications for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish technical specifications for Dynamic Disturbance Recording selected in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective which is to establish technical specifications for Dynamic Disturbance Recording selected in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R9.

VRF and VSL Justifications – PRC-002-2, R9	
Proposed Moderate VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R9.
Proposed High VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R9.
Proposed Severe VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 1% but less than or equal to 10% of the total recording properties as specified in Requirement R9.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3- Consistency among Reliability Standards**

VRF and VSL Justifications – PRC-002-2, R9	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This requirement established technical specifications for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R10	
Proposed VRF	**Lower**
NERC VRF Discussion	R10 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires time synchronization of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations established in R1 and R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failures to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective which is to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 90% but

VRF and VSL Justifications – PRC-002-2, R10	
	less than 100% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed High VSL	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have time synchronization for SER, FR, and DDR data for less than or equal to 70% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R10	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R11	
Proposed VRF	**Lower**
NERC VRF Discussion	R11 is administrative in nature and a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 provides criteria around timelines for providing the data and the data format. This is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria on providing Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R11 contains only one objective which is to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data within the specified criteria. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30 calendar days but less than 40 calendar days from the request.

VRF and VSL Justifications – PRC-002-2, R11	
	OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 113.2 provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% but less than 100% in the proper data format.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40 calendar days but less than or equal to 50 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% but less than or equal to 90% in the proper data format.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50 calendar days but less than or equal to 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided more than 70% but less than or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% but less than or equal to 80% in the proper data format.

VRF and VSL Justifications – PRC-002-2, R11	
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% in the proper data format.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R11	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R12	
Proposed VRF	**Lower**
NERC VRF Discussion	R12 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 provides criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to follow the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective which is to establish criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days but less than 100 calendar days after discovery of the failure.

VRF and VSL Justifications – PRC-002-2, R12	
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days but less than or equal to 110 calendar days after discovery of the failure.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days but less than or equal to 120 calendar days after discovery of the failure.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R12	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Project 2007-11 Disturbance Monitoring

VRF and VSL Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-002-2 – Disturbance Monitoring and Reporting Requirements.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines.

The Disturbance Monitoring and Reporting Requirements Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria –VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed VRF	**Lower**
NERC VRF Discussion	R1 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 establishes the list of Sequence of Events Recordings and Fault Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for establishing a list of BES bus locations for Sequence of Events Recording and Fault Recording using the selection procedure in Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish the list of BES bus locations for Sequence of Events Recording and Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to establish a list of BES bus locations for Sequence of Events Recording and Fault Recording and to review the list every 5 calendar years. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Lower VSL	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 80% but less than 100% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by 30 calendar days or less. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by 10 calendar days or less. ~~The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 80% but less than 100% of the required bus locations.~~ ~~OR~~ ~~The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by 30 calendar days or less.~~
Proposed Moderate VSL	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 70% but less than or equal to 80% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by greater than 10 calendar days but less than or equal to 20 calendar days.~~The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 70% but less than or equal to 80% of the required bus locations.~~ ~~OR~~ ~~The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 30 calendar days and less than or equal to 60 calendar days.~~

VRF and VSL Justifications – PRC-002-2, R1	
Proposed High VSL	The Transmission Owner identified the BES buses as directed by Requirement R1 for more than 60% but less than or equal to 70% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying the other owners by greater than 20 calendar days but less than or equal to 30 calendar days.~~The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for more than 60% but less than or equal to 70% of the required bus locations.~~ ~~OR~~ ~~The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 60 calendar days and less than or equal to 90 calendar days.~~
Proposed Severe VSL	The Transmission Owner identified the BES buses as directed by Requirement R1for less than or equal to 60% of the required BES buses. OR The Transmission Owner assessed the BES buses as directed by Requirement R1but was late by greater than 90 calendar days. OR The Transmission Owner as directed by Requirement R1 was late in notifying one or more other owners by greater than 30 calendar days. ~~The Transmission Owner identified the bus locations as directed by Requirement R1, Part 1.1 for less than or equal to 60% of the required bus locations.~~ ~~OR~~ ~~The Transmission Owner assessed the bus locations as directed by Requirement R1, Part 1.2 but was late by greater than 90 calendar days.~~

VRF and VSL Justifications – PRC-002-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VRF and VSL Justifications – PRC-002-2, R1	
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

~~VRF and VSL Justifications – PRC-002-2, R2~~	
~~Proposed VRF~~	**~~Lower~~**
~~NERC VRF Discussion~~	~~R2 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.~~
~~FERC VRF G1 Discussion~~	**~~Guideline 1- Consistency w/ Blackout Report~~** ~~R2 requires the Transmission Owner to notify the other affected owners to provide Sequence of Events Recordings and Fault Recordings at bus locations selected in Requirement R1. This is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.~~
~~FERC VRF G2 Discussion~~	**~~Guideline 2- Consistency within a Reliability Standard~~** ~~This requirement does not have parts.~~
~~FERC VRF G3 Discussion~~	**~~Guideline 3- Consistency among Reliability Standards~~** ~~This requirement calls for notifying the other affected owners to~~

~~VRF and VSL Justifications – PRC-002-2, R2~~	
	~~provide Sequence of Events Recordings and Fault Recordings at bus locations selected in Requirement R1. The team could not identify other continent-wide reliability standards of the same nature.~~
~~FERC VRF G4 Discussion~~	**~~Guideline 4- Consistency with NERC Definitions of VRFs~~** ~~Failure to notify the owners of BES bus locations for Sequence of Events Recording and Fault Recording selected in R1 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.~~
~~FERC VRF G5 Discussion~~	**~~Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation~~** ~~R2 contains only one objective which is to notify the owners of BES bus locations for Sequence of Events Recording and Fault Recording selected in R1.~~
~~Proposed Lower VSL~~	~~The Transmission Owner as directed by Requirement R2 was late in notifying the owners by 10 calendar days or less.~~
~~Proposed Moderate VSL~~	~~The Transmission Owner as directed by Requirement R2 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.~~
~~Proposed High VSL~~	~~The Transmission Owner as directed by Requirement R2 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.~~
~~Proposed Severe VSL~~	~~The Transmission Owner as directed by Requirement R2 was late in notifying one or more owners by greater than 30 calendar days.~~
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.~~
~~FERC VSL G2~~	~~Guideline 2a:~~

~~VRF and VSL Justifications – PRC-002-2, R2~~	
~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~The VSL assignment is for R2 is not binary.~~ ~~Guideline 2b:~~ ~~The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~
~~FERC VSL G3~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.~~
~~FERC VSL G4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~Proposed VSLs are based on a single violation and not a cumulative violation methodology.~~
~~FERC VSL G5~~ ~~Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs~~	~~Non CIP~~
~~FERC VSL G6~~ ~~VSLs for cyber security requirements containing~~	~~Non CIP~~

~~VRF and VSL Justifications – PRC-002-2, R2~~	
~~interdependent tasks of documentation and implementation should account for their interdependence~~	

VRF and VSL Justifications – PRC-002-2, R2~~3~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R2~~3~~ is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2~~3~~ provides criteria for Sequence of Events Recording which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Sequence of Events Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Sequence of Events Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2~~3~~ contains only one objective which is to establish criteria for Sequence of Events Recording. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R2~~3~~	
Proposed Lower VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 75% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.~~Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 75% but less than 100% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations established in Requirement R1.~~
Proposed Moderate VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 50% but less than or equal to 75% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.~~Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 50% but less than or equal to 75% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations established in Requirement R1.~~
Proposed High VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 10% but less than or equal to 50% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.~~Each Transmission or Generator Owner as directed by Requirement R3 implemented more than 10% but less than or equal to 50% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations established in Requirement R1.~~
Proposed Severe VSL	Each Transmission or Generator Owner as directed by Requirement R2 had from 0% but less than or equal to 10% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.~~Each Transmission or Generator Owner as directed by Requirement R3 implemented from 0% but less than or equal to 10% of the total Sequence of Events Recording for circuit breaker position (open/close) for each of the circuit breakers at the bus locations established in Requirement R1.~~
FERC VSL G1	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1

VRF and VSL Justifications – PRC-002-2, R2~~3~~	
Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	(enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2~~3~~ is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5	Non CIP

VRF and VSL Justifications – PRC-002-2, R2~~3~~	
Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R3~~4~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R3~~4~~ is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R~~4~~3 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect

VRF and VSL Justifications – PRC-002-2, R3~~4~~	
	the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3~~4~~ contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 75% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.~~The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 75% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.~~
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 50% but less than or equal to 75% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.~~The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 50% but less than or equal to 75% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.~~
Proposed High VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 10% but less than or equal to 50% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.~~The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that~~

VRF and VSL Justifications – PRC-002-2, R3~~4~~	
	~~covers more than 10% but less than or equal to 50% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.~~
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 0% but less than or equal to 10% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.~~The Transmission Owner or Generator Owner implemented Fault Recording as directed by Requirement R4, Parts 4.1 and 4.2 that covers more than 0% but less than or equal to 10% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R3~~4~~	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R4~~5~~

VRF and VSL Justifications – PRC-002-2, R4~~5~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R4~~5~~ is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4~~5~~ provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recordings selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4~~5~~ contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R4.~~The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R5.~~
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data that meets

VRF and VSL Justifications – PRC-002-2, R4~~5~~	
	more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R4.~~The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R5.~~
Proposed High VSL	The Transmission Owner or Generator Owner had FR data that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R4.~~The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R5.~~
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data that meets more than 0% but less than or equal to 10% of the total recording properties as specified in Requirement R4.~~The Transmission Owner or Generator Owner implemented Fault Recording that meets more than 0% but less than or equal to 10% of the total recording properties as specified in Requirement R5.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R45	
Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R~~6~~5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5~~6~~ is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R~~6~~5 establishes the list of Dynamic Disturbance Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for identifying BES Elements for Dynamic Disturbance Recording. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to identify BES Elements for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5~~6~~ contains only one objective which identifies BES Elements within specified criteria and to review the list every 5 calendar years. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R5 for more than 80% but less than 100% of the required Elements. OR

VRF and VSL Justifications – PRC-002-2, R~~6~~5	
	The Responsible Entity assessed the Elements for DDR as directed by Requirement R5 but was late by 30 calendar days or less. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by 10 calendar days or less. ~~The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 80% but less than 100% of the required Elements.~~ ~~OR~~ ~~The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by 30 calendar days or less.~~
Proposed Moderate VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R5 but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.~~The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 70% but less than or equal to 80% of the required Elements.~~ ~~OR~~ ~~The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 30 calendar days and less than or equal to 60 calendar days.~~
Proposed High VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required Elements. OR

VRF and VSL Justifications – PRC-002-2, R~~6~~5	
	The Responsible Entity assessed the Elements for DDR as directed by Requirement R5 but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.~~The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for more than 60% but less than or equal to 70% of the required Elements.~~ ~~OR~~ ~~The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 60 calendar days and less than or equal to 90 calendar days.~~
Proposed Severe VSL	The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R5 for less than or equal to 60% of the required Elements. OR The Responsible Entity assessed the Elements for DDR as directed by Requirement R5 but was late by greater than 90 calendar days. OR The Responsible Entity as directed by Requirement R5 was late in notifying one or more owners by greater than 30 calendar days.~~The Responsible Entity accurately identified the Elements for DDR as directed by Requirement R6, Part 6.1 for less than or equal to 60% of the required Elements.~~ ~~OR~~ ~~The Responsible Entity assessed the Elements for DDR as directed by Requirement R6, Part 6.2 but was late by greater than 90 calendar days.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture

VRF and VSL Justifications – PRC-002-2, R~~6~~5	
Consequence of Lowering the Current Level of Compliance	data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5~~6~~ is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer	Non CIP

VRF and VSL Justifications – PRC-002-2, R~~6~~5	
network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

~~VRF and VSL Justifications – PRC-002-2, R7~~	
~~**Proposed VRF**~~	~~**Lower**~~
~~NERC VRF Discussion~~	~~R7 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.~~
~~FERC VRF G1 Discussion~~	~~**Guideline 1- Consistency w/ Blackout Report**~~ ~~R7 requires the Responsible Entity to notify the owners to provide Dynamic Disturbance Recordings for Elements selected in R6. This is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.~~
~~FERC VRF G2 Discussion~~	~~**Guideline 2- Consistency within a Reliability Standard**~~ ~~This requirement does not have parts.~~
~~FERC VRF G3 Discussion~~	~~**Guideline 3- Consistency among Reliability Standards**~~ ~~This requirement calls for the Responsible Entity to notify the owners of the Elements for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards~~

~~VRF and VSL Justifications – PRC-002-2, R7~~	
	~~of the same nature.~~
~~FERC VRF G4 Discussion~~	~~**Guideline 4- Consistency with NERC Definitions of VRFs**~~ ~~Failure to notify the owners of the Elements selected for Dynamic Disturbance Recording in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.~~
~~FERC VRF G5 Discussion~~	~~**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**~~ ~~R7 contains only one objective which is to notify the owners of BES Elements selected for Dynamic Disturbance Recording selected in R6.~~
~~Proposed Lower VSL~~	~~The Responsible Entity as directed by Requirement R7 was late in notifying the owners by 10 calendar days or less.~~
~~Proposed Moderate VSL~~	~~The Responsible Entity as directed by Requirement R7 was late in notifying the owners by greater than 10 calendar days but less than or equal to 20 calendar days.~~
~~Proposed High VSL~~	~~The Responsible Entity as directed by Requirement R7 was late in notifying the owners by greater than 20 calendar days but less than or equal to 30 calendar days.~~
~~Proposed Severe VSL~~	~~The Responsible Entity as directed by Requirement R7 was late in notifying one or more owners by greater than 30 calendar days.~~
~~**FERC VSL G1**~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.~~
~~**FERC VSL G2**~~ ~~Violation Severity Level~~	~~Guideline 2a:~~ ~~The VSL assignment is for R7 is not binary.~~

~~VRF and VSL Justifications – PRC-002-2, R7~~	
~~Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~Guideline 2b:~~ ~~The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~
~~**FERC VSL G3**~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.~~
~~**FERC VSL G4**~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~	~~Proposed VSLs are based on a single violation and not a cumulative violation methodology.~~
~~**FERC VSL G5**~~ ~~Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs~~	~~Non CIP~~
~~**FERC VSL G6**~~ ~~VSLs for cyber security requirements containing interdependent tasks of~~	~~Non CIP~~

~~VRF and VSL Justifications – PRC-002-2, R7~~	
~~documentation and implementation should account for their interdependence~~	

VRF and VSL Justifications – PRC-002-2, R6~~8~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R6~~8~~ is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6~~8~~ provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R5~~6~~. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar

VRF and VSL Justifications – PRC-002-2, R6~~8~~	
	requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.~~The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 and 8.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.~~
Proposed Moderate VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.~~The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.~~
Proposed High VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.~~The Transmission Owner implemented DDR as directed by Requirement R8, Parts 8.1 through 8.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.~~
Proposed Severe VSL	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.~~The Transmission Owner failed to implement DDR as directed by Parts 8.1 through 8.4.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared

VRF and VSL Justifications – PRC-002-2, R6~~8~~	
the Current Level of Compliance	between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic,	Non CIP

VRF and VSL Justifications – PRC-002-2, R6~~8~~	
should apply binary VSLs	
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R7~~9~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R7~~9~~ is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7~~9~~ provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could

VRF and VSL Justifications – PRC-002-2, R7~~9~~	
	not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7~~9~~ contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.~~The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 that covers more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.~~
Proposed Moderate VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.~~The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.~~
Proposed High VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.~~The Generator Owner implemented DDR as directed by Requirement R9, Parts 9.1 through 9.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.~~
Proposed Severe VSL	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.~~The Generator Owner failed to implement DDR as directed by Requirement R9, Parts 9.1 through 9.4.~~

VRF and VSL Justifications – PRC-002-2, R7~~9~~	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R7~~9~~ is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VRF and VSL Justifications – PRC-002-2, R7~~9~~	
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R8~~10~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R8~~10~~ is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8~~10~~ provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.

VRF and VSL Justifications – PRC-002-2, R8~~10~~	
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes the need for continuous data recording and storage for Dynamic Disturbance Recordings established in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R5~~6~~ could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8~~10~~ contains only one objective to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 75% but less than 100% of the Elements they own as determined in Requirement R5.~~The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 75% but less than 100% of the Elements they own as determined in Requirement R6.~~
Proposed Moderate VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 50% but less than or equal to 75% of the Elements they own as determined in Requirement R5.~~The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 50% but less than or equal to 75% of the Elements they own as determined in Requirement R6.~~
Proposed High VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 0% but less than or equal to 50% of the Elements they own as

VRF and VSL Justifications – PRC-002-2, R8~~10~~	
	determined in Requirement R5.~~The Transmission Owner or Generator Owner implemented continuous or non-continuous DDR, as directed in Requirement R10, for more than 0% but less than or equal to 50% of the Elements they own as determined in Requirement R6.~~
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the Elements they own as determined in Requirement R5.~~The Transmission Owner or Generator Owner failed to implement continuous or non-continuous DDR, as directed in Requirement R10, for the Elements they own as determined in Requirement R6.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R8~~10~~ is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the

VRF and VSL Justifications – PRC-002-2, R8~~10~~	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R9~~11~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R9~~11~~ is a requirement in a long-term planning time frame that, if

VRF and VSL Justifications – PRC-002-2, R9~~11~~	
	violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9~~11~~ provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement established technical specifications for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish technical specifications for Dynamic Disturbance Recording selected in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9~~11~~ contains only one objective which is to establish technical specifications for Dynamic Disturbance Recording selected in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R9.~~The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 75% but less than 100% of the total recording properties as specified in Requirement R11.~~
Proposed Moderate VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 50% but less than or equal to 75% of the total recording

VRF and VSL Justifications – PRC-002-2, R9~~11~~	
	properties as specified in Requirement R9.~~The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 50% but less than or equal to 75% of the total recording properties as specified in Requirement R11.~~
Proposed High VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R9.~~The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 10% but less than or equal to 50% of the total recording properties as specified in Requirement R11.~~
Proposed Severe VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 1% but less than or equal to 10% of the total recording properties as specified in Requirement R9.~~The Transmission Owner or Generator Owner implemented Dynamic Disturbance Recording that meets more than 1% but less than or equal to 10% of the total recording properties as specified in Requirement R11.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is	Guideline 2a: The VSL assignment is for R9~~11~~ is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R9~~11~~	
Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	**Guideline 3- Consistency among Reliability Standards** This requirement established technical specifications for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R10~~12~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R10~~2~~ is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10~~2~~ requires time synchronization of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations established in R1 and R5~~6~~. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failures to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10~~2~~ contains only one objective which is to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 90% but less than 100% of the bus locations as per Requirements R1 and

VRF and VSL Justifications – PRC-002-2, R10~~12~~	
	Elements as per Requirement R5 as directed by Requirement R10. ~~The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 90% but less than 100% of the bus locations established in Requirements R1 and Elements established in Requirement R6 as directed by Requirement R12.~~
Proposed Moderate VSL	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10. ~~The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 80% but less than or equal to 90% of the bus locations established in Requirements R1 and Elements established in Requirement R6 as directed by Requirement R12.~~
Proposed High VSL	The Transmission Owner or Generator Owner had time synchronization for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10. ~~The Transmission Owner or Generator Owner implemented time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for more than 70% but less than or equal to 80% of the bus locations established in Requirements R1 and Elements established in Requirement R6 as directed by Requirement R12.~~
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have time synchronization for SER, FR, and DDR data for less than or equal to 70% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10. ~~The Transmission Owner or Generator Owner failed to implement time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording for less than 70% of the bus locations established in Requirements R1 and Elements established in~~

VRF and VSL Justifications – PRC-002-2, R10~~12~~	
	~~Requirement R6 as directed by Requirement R12.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R10~~2~~ is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VRF and VSL Justifications – PRC-002-2, R10~~12~~	
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R11~~3~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R11~~3~~ is administrative in nature and a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11~~3~~ provides criteria around timelines for providing the data and the data format. This is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.

VRF and VSL Justifications – PRC-002-2, R11~~3~~	
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria on providing Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5~~6~~.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5~~6~~ could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R11~~3~~ contains only one objective which is to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data within the specified criteria. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30 calendar days but less than 40 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 113.2 provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% but less than 100% in the proper data format. ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 30 calendar days but less than 40 calendar days from the request.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 90% but less than~~

VRF and VSL Justifications – PRC-002-2, R11~~3~~	
	~~100% of the requested data.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 90% but less than 100% in the proper data format.~~
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40 calendar days but less than or equal to 50 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% but less than or equal to 90% in the proper data format. ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 40 calendar days but less than or equal to 50 calendar days from the request.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 80% but less than or equal to 90% of the requested data.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 80% but less than or equal to 90% in the proper data format.~~
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50 calendar days but less than or equal to 60 calendar days from the request. OR

VRF and VSL Justifications – PRC-002-2, R11~~3~~	
	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided more than 70% but less than or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% but less than or equal to 80% in the proper data format. ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 provided the requested data more than 50 calendar days but less than or equal to 60 calendar days from the request.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 provided more than 70% but less than or equal to 80% of the requested data.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided more than 70% but less than or equal to 80% in the proper data format.~~
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60 calendar days from the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% in the proper data format.~~The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.1 failed to provide the requested data more than 60 calendar days from the request.~~

VRF and VSL Justifications – PRC-002-2, R1~~3~~	
	~~OR~~ ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Part 13.2 failed to provide less than or equal to 70% of the requested data.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner as directed by Requirement R13, Parts 13.3 through 13.5 provided less than or equal to 70% in the proper data format.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R1~~3~~ is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-002-2, R11~~3~~	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R12~~4~~	
Proposed VRF	**Lower**
NERC VRF Discussion	R124 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to

VRF and VSL Justifications – PRC-002-2, R12~~4~~	
	effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12~~4~~ provides criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to follow the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12~~4~~ contains only one objective which is to establish criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days but less than 100 calendar days after discovery of the failure. ~~The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 calendar days but less than 100 calendar days after discovery of the failure.~~
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days but less than or equal to 110 calendar days after discovery of the failure. ~~The~~

VRF and VSL Justifications – PRC-002-2, R1~~2~~4	
	~~Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 calendar days but less than or equal to 110 calendar days after discovery of the failure.~~
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days but less than or equal to 120 calendar days after discovery of the failure. ~~The Transmission Owner or Generator Owner as directed by Requirement R14 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 calendar days but less than or equal to 120 calendar days after discovery of the failure.~~
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. ~~The Transmission Owner or Generator Owner as directed by Requirement R14 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure.~~
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level	Guideline 2a: The VSL assignment is for R12~~4~~ is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R12~~4~~	
Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2007-11 Disturbance Monitoring

Additional Ballot and Non-Binding Poll Now Open through June 23, 2014

Now Available

An additional ballot and for **PRC-002-2 - Disturbance Monitoring and Reporting Requirements** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are now open through **8 p.m. Eastern on Monday, June 23, 2014**.

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2007-11 Disturbance Monitoring

Formal Comment Period Now Open through June 23, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: June 13-23, 2014

Now Available

A 45-day formal comment period for **PRC-002-2 - Disturbance Monitoring and Reporting Requirements** is open through **8 p.m. Eastern on Monday, June 23, 2014**.

Instructions for Commenting
Please use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
An additional ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 13-23, 2014**.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Standards Announcement

Project 2007-11 Disturbance Monitoring

Formal Comment Period Now Open through June 23, 2014

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Additional Ballot and Non-Binding Poll: June 13-23, 2014

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Standards Announcement

Project 2007-11 Disturbance Monitoring

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot and for **PRC-002-2 - Disturbance Monitoring and Reporting Requirements** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded **8 p.m. Eastern on Wednesday, June 25, 2014**.

The standard achieved a quorum, but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Ballot	Non-Binding Poll
Quorum / Approval	**Quorum / Supportive Opinions**
77.69% / 52.29%	76.18% / 59.60%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

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Ballot Results	
Ballot Name:	Project 2007-11 DM
Ballot Period:	6/13/2014 - 6/25/2014
Ballot Type:	Additional
Total # Votes:	296
Total Ballot Pool:	381
Quorum:	**77.69 % The Quorum has been reached**
Weighted Segment Vote:	52.29 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	101	1	44	0.595	30	0.405	0	7	20
2 - Segment 2	8	0.5	0	0	5	0.5	0	2	1
3 - Segment 3	85	1	33	0.579	24	0.421	0	8	20
4 - Segment 4	29	1	10	0.476	11	0.524	0	3	5
5 - Segment 5	87	1	28	0.491	29	0.509	0	7	23
6 - Segment 6	51	1	24	0.615	15	0.385	0	1	11
7 - Segment 7	4	0.1	0	0	1	0.1	0	0	3
8 - Segment 8	5	0.5	2	0.2	3	0.3	0	0	0
9 - Segment 9	3	0.1	1	0.1	0	0	0	0	2

10 - Segment 10	8	0.6	5	0.5	1	0.1	0	2	0
Totals	**381**	**6.8**	**147**	**3.556**	**119**	**3.244**	**0**	**30**	**85**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater	Negative	COMMENT RECEIVED
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Hudson Gas & Electric Corp.	Frank Pace		
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (CIPCO supports comments submitted by ACES.)
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Negative	COMMENT RECEIVED
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
				SUPPORTS THIRD PARTY

1	Gainesville Regional Utilities	Richard Bachmeier	Negative	COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	COMMENT RECEIVED
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnesota Power, Inc.	Randi K. Nyholm	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Montana Dakota Utilities Co.	Teresa Hendrickson	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Portland General Electric will be submitting comments separately.)
1	Potomac Electric Power Co.	David Thorne	Affirmative	
				SUPPORTS THIRD PARTY COMMENTS - (Refer to comments

1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	submitted on behalf of PPL Corporation NERC Registered Affiliates.)
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Sam Rayburn G&T Inc.	William M Bateman		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
1	South Texas Electric Cooperative	Renee Davidson		
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED

2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Standards Review Commitee)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Amy J Miller	Negative	COMMENT RECEIVED
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Homestead	Orestes J Garcia		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Charles Morgan		
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon-Exelon)
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Negative	COMMENT RECEIVED
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
3	El Paso Electric Company	Rhonda Bryant		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	

3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corp)
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Guadalupe Valley Electric Cooperative	Robert B Christmas		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter		
3	Lee County Electric Cooperative	David A Hadzima		
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NRC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Abstain	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid comments)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by Nebraska Public Power District)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill		

3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS COMMENTS of Chris Mattson
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	COMMENT RECEIVED
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Abstain	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corporation)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by Florida Municipal Power Agency)
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	

4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of SEC Corporate Compliance)
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (support comments entered by Barb Kedrowski)
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren's comments)
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Negative	COMMENT RECEIVED
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		

5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Energy	Mark Stefaniak	Negative	COMMENT RECEIVED
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Negative	COMMENT RECEIVED
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon-Exelon)
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	Invenergy LLC	Alan Beckham	Affirmative	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	NaturEner USA, LLC	Andrew S Ace		
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
				SUPPORTS

5	Oglethorpe Power Corporation	Bernard Johnson	Negative	THIRD PARTY COMMENTS - (SERC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NRC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema		
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric, Michael Haff)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	COMMENT RECEIVED
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
				SUPPORTS

6	Colorado Springs Utilities	Shannon Fair	Negative	THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon-Exelon)
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz		
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE Transmission)
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet		
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
				SUPPORTS THIRD PARTY COMMENTS - (see comments

6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	submitted on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	Alcoa, Inc.	Thomas Gianneschi		
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration LP)
7	Praxair Inc.	David Meade		
7	Valero Services, Inc.	Lee W Morris		
8		Debra R Warner	Affirmative	
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Utilities)
8		David L Kiguel	Negative	COMMENT RECEIVED
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
9	New York State Public Service Commission	Diane J Barney		
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC comments from the PCS)
10	Southwest Power Pool RE	Emily Pennel	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

Non-Binding Poll Results

Project 2007-11 Disturbance Monitoring

Non-Binding Poll Results	
Non-Binding Poll Name:	2007-11 DM Non-Binding Poll_sc_1
Poll Period:	6/13/2014 - 6/25/2014
Total # Opinions:	259
Total Ballot Pool:	340
Summary Results:	76.18% of those who registered to participate provided an opinion or an abstention; 59.60% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater	Negative	COMMENT RECEIVED
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Iowa Power Cooperative	Kevin J Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper		

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Negative	COMMENT RECEIVED
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	

1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Portland General Electric will be submitting comments separately.)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL Corporation NERC Registered Affiliates.)
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Sam Rayburn G&T Inc.	William M Bateman		

NERC

1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Corporate Compliance)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
1	South Texas Electric Cooperative	Renee Davidson		
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(ISO/RTO Standards Review Commitee)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Amy J Miller	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz		
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Charles Morgan		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	El Paso Electric Company	Rhonda Bryant		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	

3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corp)
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Guadalupe Valley Electric Cooperative	Robert B Christmas		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Brett Holland)
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace D Hunter		
3	Lee County Electric Cooperative	David A Hadzima		
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Abstain	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC comments)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	

3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill		
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
3	Tacoma Public Utilities	Travis Metcalfe	Negative	COMMENT RECEIVED Chris Mattson
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City Utilities of Springfield, Missouri	John Allen	Negative	COMMENT RECEIVED
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring		
4	Detroit Edison Company	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia

				Transmission Corporation)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by Floriday Municipal Power Agency)
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of SEC Corporate Compliance)
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (support comments entered by Barb Kedrowski)
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Negative	COMMENT RECEIVED
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Abstain	
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	DTE Energy	Mark Stefaniak	Negative	COMMENT RECEIVED
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Negative	COMMENT RECEIVED
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida

				Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NRC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema		

5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric, Michael Haff)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	COMMENT RECEIVED
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
6	AEP Marketing	Edward P. Cox	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Affirmative	

6	Luminant Energy	Brenda Hampton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz		
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PGE Transmission)
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet		
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC PCS)
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (see comments submitted on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	

6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Alcoa, Inc.	Thomas Gianneschi		
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration LP)
7	Praxair Inc.	David Meade		
8		Debra R Warner	Affirmative	
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Utilities)
8		David L Kiguel	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from the SERC PCS)
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

Individual or group. (67 Responses)
Name (45 Responses)
Organization (45 Responses)
Group Name (22 Responses)
Lead Contact (22 Responses)
Question 1 (52 Responses)
Question 1 Comments (61 Responses)
Question 2 (55 Responses)
Question 2 Comments (61 Responses)
Question 3 (0 Responses)
Question 3 Comments (61 Responses)

Individual
David Jendras
Ameren
No
(1) In addition to our comments we adopt the SERC PCS comments, and include them by reference. (2) As we have stated in our previous comments, we have installed over 30 PMUs on our system over the last 3 years in conjunction with our Planning Coordinator. This required significant effort and resources to perform this installation work. Even though they have not yet been needed for disturbance analysis, some operating visualization tools are being used and we have reviewed some minor perturbations. We respectfully disagree with the drafting team's brief justification in the Rationale for R5. We still believe the resultant number of PMUs which might be needed under the new standard would be burdensome to most entities. (3) Our software vendor has made known to us that they do not presently have the full capability as described in Requirement 11 implemented in our data concentrator software.
Group
Dominion
Mike Garton
Yes
Yes
As stated in Dominion's previous comments: "PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01)." The standard drafting team (SDT) in response provided: "The DMSDT is aware that the NPCC DMSDT has been reconvened to review the Regional Standard with respect to PRC-002-2 after it is approved." While Dominion appreciates the SDT response, the fact remains that NPCC applicable entities continue to implement the FERC approved NPCC Regional Reliability Standard that could result in over/under installing DM capability when compared to PRC-002-2, once approved. Therefore, Dominion again urges the SDT to include a Variance in PRC-002-2 that excludes entities subject to PRC-002-NPCC-01 from the applicability section of this standard.
Group
Northeast Power Coordinating Council

Guy Zito
Yes
The term BES bus is not a defined term, it is only described in Step 1 of Attachment 1. Note that NERC's Definition of Bulk Electric System (Phase 2) definition applies to Elements. Requirement R3, sub-Part 3.1 requires to have "Phase-to-neutral voltages for each phase of each specified BES bus". Since BES buses, as described in Attachment 1, may not represent physical buses, this sub-Part is not clear. For example, a breaker-and-a-half design with two physical buses. A Transmission Owner (TO) might not have visibility of the BES classification of Elements it does not own. It is recommended that the TO provide the list of identified BES buses to their PC / RC. The PC/RC will review the received list from the TO, and determine if the list contains BES Elements owned by others, and notify those owners whose BES Elements may require sequence of events recording (SER) and/or fault recording (FR) data. Reference to (undefined) BES buses in Requirement R5 makes this requirement open to interpretations. Sub-Part 5.1.2 requires the inclusion of "Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity", and its bullets include stability related interfaces or other significant Flowgates, Elements associated with Interconnection Reliability Operating Limits (IROLs), and voltage stability limited transfer paths or load serving areas. The different Parts and sub-Parts of R5 could require a large number of DDRs for TOs which have Flowgates, IROLs, and /or UVLS schemes. The number of required DDRs could become significantly larger than the minimum set of one BES Element plus one additional BES Element for each additional 3,000 MW of load, which could cause excessive burden on some TOs. It is also suggested to eliminate the potential overlap of sub-Parts 5.1.2, 5.1.4, and 5.1.5 by consolidating sub-Parts. Finally, it is recommended that "One or more BES Elements associated with Interconnection Reliability Operating Limits (IROLs)" in sub-Part 5.1.4 be replaced with "Any one BES Element critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" to be consistent with the language in CIP-002-5.1. Sub-Part 5.1.4 requires clarification. The Drafting Team should consider shortening R1 by listing Parts.
Yes
There should be consistency between Parts 5.1.2, 5.1.4, and 5.1.5. The Drafting Team in 5.1.2 and 5.1.5 require DDR on ANY ONE BES Element but in 5.1.4 it uses "One or more BES Elements…". Reading the DT response to the last comment round it seems the intent was to be consistent for these three items; only one BES is required to be monitored. If true then standardize on ANY ONE BES element. Refer to the comments in Question 1.
An additional implementation requirement or effective date should be included to address the situation when after the 5 year evaluation an additional element is identified for FR or DDR to afford the TO or GO to budget and install additional equipment. The draft PRC-005-X standard included language to address this in its latest draft. Consider adding to the technical guidelines for R6 more information surrounding the allowance for the use of a common bus voltage measurement where appropriate to monitor multiple BES Elements. Suggest adding to the second paragraph in the guideline for R6: The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the Standard is not to require measurement of each BES Element where a common bus measurement is available. Where a common measurement is utilized the Owner must plan the installation such that a bus outage would not result in the DDR data to be compromised. For example,…etc….. Part 11.4 requires the use of C37.111-2013. This could be an issue if an Entity has not upgraded its equipment of firmware. In R8 an exception is allowed for DDR owners with older equipment. A similar tack should be applied here. The Standard should not force replacement. Attachment 1 does not specify how to distribute an odd number for 20% of the BES buses between 10% of the BES buses and additional 10% of the BES buses (both determined in Step 6), e.g. if twenty-one (21) buses in total are required. Requirement R8 should allow legacy equipment to have multiple triggered records which when combined into one time synchronized record make up the required length of three minutes. Requirement R11, Part 11.3 requires SER data in Comma Separated Value (.CSV) format following Attachment 2 whereas the majority of Disturbance Monitoring Equipment (DME) does not save data in this format. Can the Drafting Team provide a name of DME which gives the data in this format? Requirement R11, Part 11.4 requires FR and DDR data in C37.111 (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE) formatted files whereas the majority of DME equipment does not save data in this format. Are manually converted records acceptable? Requirement R11, Part 11.5 requires data files

to be named in conformance with C37.232 IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME) whereas the majority of DME equipment does not save data in this format.
Individual
Leonard Kula
Independent Electricity System Operator
No
We agree with the merging of R2 into R1, but not the revised R5 which combined R6 and R7. Please see our comments under Q2, below.
No
(a) R5 is unclear as it mixes BES Buses with BES Elements. If the responsible entity (a PC or an RC) is to identify BES Elements for which dynamic disturbance recording (DDR) data is required, then it needs to notify ALL such Elements' owners, and there is no need to mention "of BES Elements connected to those BES buses". However, if the requirement is intended to ask the responsible entity to identify BES buses for which dynamic disturbance recording (DDR) data is required, then it needs to notify the owners of the BES buses AND the owners of the BES Elements connected to these BES buses. We suggest the SDT to review the intent of the requirement, and revise it to clearly convey the requirements on what is it the responsible entity needs to identify, and to whom it needs to notify. (b) Part 5.1.2: The term "significant Flowgates" is subject to interpretation since it is not clear what "significant" really means. We suggest the SDT to clarify this term or provide more specificity. (c) Part 5.1.4: It is not clear whether or not the BES Element associated with an IROL is the monitored element or the contingent element or both. This needs to be clarified. (d) Part 5.2: This part requires adding one BES Element for each additional 3,000 MW of an entity's historical peak system Demand, but the word "its" is unclear whether it means the responsible entity (in this case the PC or RC) or the BA. We suggest to reword it to clearly convey that it is the responsible entity's area historical peak system Demand. Note that additional clarity may be needed if the "its" refers to a PC or RC area since within a PC or RC area, there may be multiple BAs and TOPs within which their system peak demand could occur at different times. Thus, Part 5.2 needs to clearly convey whether it is the total non-simultaneous peak demands of all BAs within an area, or it is the one-of highest demand of the entire area
Group
Peak Reliability
Jared Shakespeare
No
The initial list of locations should come from the owners (TOs and GOs) with a subsequent review process as identified by the Responsible Entity. The Responsible Entity should have the authority to require additions as it sees necessary. Owners should provide the initial list because they have access to the information and would bear the cost of installing DDRs.
No
The reference to the WECC Path Rating Catalog should be removed because the remaining bullet points cover everything in the Path Rating Catalog. The WECC Path Rating Catalog can be changed without going through any Standard development process. Changes to the Path Rating Catalog changes Requirement impact.
Applicability section: the Responsible Entity in all Interconnections should be the Planning Coordinator or Reliability Coordinator. R5.1.2, bullet 1, the term "significant Flowgates" appears to be undefined. Does it need to be clarified? R8: undervoltage trigger set no lower than 85% of normal operating voltage – what is normal operating voltage? For a 500 kV sysem, is it 500 kV or is it the average bus voltage for a specified period of time (such as 525kV)?
Individual
Jo-Anne Ross
Manitoba Hydro
Yes

Yes
1. Implementation Plan- The first paragraph simply describes a date that is synonymous with the Effective Date of the Standard. Accordingly, Manitoba Hydro recommends that this paragraph be abbreviated and made consistent with the third paragraph, by stating that:" Entities shall be 100% compliant on the Effective Date." 2. Similarly, the second paragraph under Implementation Plan describes a date that is three months after the Effective Date of the standard. Manitoba Hydro recommends that the wording be revised to state that:"Entities shall be 100% compliant within three months after the Effective Date. 3. R1 requires transmission Owners to notify other owners that certain BES Elements may require SER/ FR data within 90 days, however it does not specify when the 90 day period runs from. This could be interpreted as running from the Effective Date of the standard or from the day that the BES Element is identified(which could be prior to the Effective Date given that entities must be compliant with applying the methodology and identifying BES busses for which data is required as of the Effective date) . Manitoba Hydro therefore recommends that the ninety day period be clarified. 4. R5-(i) For the same reasons stated above, Manitoba Hydro recommends that the ninety day period be clarified. (ii) The contents of the notice to other owners (i.e. that certain BES elements "may" require data) conflicts with R7 which "requires" that an owner who has been notified to determine certain electrical quantities. Therefore, Manitoba Hydro recommends that the "may" in R5 be deleted.
Individual
Tracy Richardson
Springfield Utility Board
• Requirement 4, specifically 4.1, requires a single record or multiple records that include "a pre-trigger record length of at least 30 cycles for the same trigger point, or at least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder." This 32-total cycle creates a limit on SUB's ability to store event reports, and we assume is does for many others, as well. Much of the commonly used and standard software, including that used by Springfield Utility Board, utilizes a 30-cycle event report (2 cycles pre-fault and 28 cycles post-trigger. It does not seem unreasonable to change the language from 32 cycles to 30, so that entities will not incur the unnecessary expense of either purchasing new software or developing a work-around with their current software. • The "buses" language in Attachment 1, Step 7 should be clarified. SUB believes it should read "bus" and not "buses".
Individual
John Allen
City Utilities of Springfield, MO
No
We support the merging of R2 into R1 and R7 into new R5. However, we do not support R1 Attachment 1 methodology regarding identifying BES buses for locating SER & FR devices to capture SER & FR data. See comments in question #3 for our reasoning.
No
The R5 language is confusing to me. It appears the Responsible Entity is charged with identifying Elements (not buses), but then the requirement language shifts to notifying owners of Elements connected to "those BES buses" and later reevaluating "identified buses". How are the buses "identified"? Is this an oversight based on the changes made to the earlier version of the Standard? Please clarify.
We continue to believe the Attachment 1 fault MVA threshold established in R1 to identify potential buses from which to pick locations for FR (and SER) data is too low. To provide a context for our comment, our system has a peak load of 800 MW serving approximately 110,000 customers in a service territory covering 320 square miles (less than one county) with local generating capacity of 1100 MW. This is a very compact system containing a relatively small geographic footprint with 17 BES buses as defined within this draft standard. All of these 17 BES buses have fault MVA above the 1500 MVA threshold, ranging from 8,000 MVA down to 2,900 MVA with a median value (bus 6 out of the top 11) of 5,800 MVA. The top 10 BES buses on our system all have a fault MVA above 5,000.

This PRC-002-2 draft Standard will require us to have FR data for 4 buses (20%) overall. The top 2 BES buses (10%) where FR data would be required will be electrically less than 2 miles apart. The other 2 buses (additional 10%) would be located 25 miles or less electrically from the first 2 buses regardless of how we elected to determine these locations. All this data will be electrically concentrated in a small geographical area, which doesn't appear to lead to a wide-area view of the overall BES. Additionally, several of the above mentioned buses have only two (2) BES sources (Distribution buses with only 2 transmission lines connected) or tapped buses with Distribution transformer(s) and no transmission breakers. Are these buses really important to the BES in the context of DME data? It seems the PRC-002-2 R1 Attachment 1 method only serves to unnecessarily inflate the number of BES buses on which the overall percentage of required locations will be calculated. We recognize the difficulty the SDT had in determining the appropriate coverage for FR data, but contend that a fault MVA threshold closer to 4500 MVA and an overall coverage percentage of 10% is adequate. This would still result in our system having FR data at 2 buses which could be electrically separated by approximately 25 miles. Additionally, we believe buses with only limited sources from the BES should be excluded out-of-hand by some other "test" mechanism within the Attachment 1 document or some other vehicle. Regarding R3: 1) Is it the intent of the Standard that FR data is to be determined for all currents defined on all Elements connected to a selected bus for any single fault on any Element connected to the bus? (i.e. if using digital relays for FR, do relays on each element (line or transformer) need to trigger for faults on any element connected to that bus?) 2) What are the expectations for faults and/or disturbances located remotely from the selected bus – how sensitive are they expected to be? In reality, are these FR devices expected to be a lower level disturbance recorder? 3) If data is expected to be available for conditions other than just faults, the data should not be classified as Fault Recording data or at least further definition/clarification should be provided. 4) Some of the discussion in the rationale box for R3 seems to suggest the FR data be used for fault analysis, as it applies to determining correct and incorrect breaker operations – Misoperation determination. In the case of installed modern microprocessor relays, the protective relay(s) should be able to determine the nature of the fault, the elements that operated, fault location, voltages and currents and many other particulars associated with a fault. Generally, FR is an unnecessary addition of equipment in these situations from the perspective of fault analysis to determine the correctness of protection system operation. Regarding R4: We propose changing the 30 cycle post trigger record length in the first bullet under R4.1 to a total record length of 30 cycles. The current wording requires a 32 cycle minimum total record length. We believe the 30 cycle total record length better matches existing microprocessor relay functionality for those that may wish to employ them in this fashion.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
ATC asks that the SDT consider the following recommended changes to add clarity to the subrequirements: R5.1.2, bullet 1 – Add "as judged by the Responsible Entities," to end of statement. R5.1.2, bullet 4 – Add "(not local Balancing Authorities)" after "Balancing Authority." R5.1.2, bullet 5 – Add "as judged by the Responsible Entities," to end of statement. R5.2.2 – Add "within the past 10 years" to the end of statement for time clarity.
Individual
Barbara Kedrowski
Wisconsin Electric Power Co
Yes
Yes
• R1: We suggest that the intent should be that the buses selected according to Attachment 1 will only be those that operate at or above 100 kv ? We believe that this should be specified in

Attachment 1. • R2: The Measure M2, Part (1), should be changed to “documents describing the device interconnections and configurations which MAY include a single design standard as representative for common installations… “. This will provide greater clarity that a single design standard is sufficient for evidence, but that it is not required. • R2, Measure M2: In addition, as acceptable evidence, the list in M2 should also include “station drawings” as allowed in M10. • R3: The Measure M3, Part (1), should be changed to “documents describing the device specifications and configurations which may include a single design standard as representative for common installations;”, similar to the wording in R2. As written, the Measure would require entities to have a “single design standard”, which is not part of the standard Requirements. In addition, a new Part (3) should be added to allow “station drawings” as permissible evidence • R3 and R4: The Generator Owner is listed here, but it is not clear what requirements apply to it, if it does not own any equipment listed in 3.1 or 3.2. In light of the SDT’s statements about the superiority of dynamic disturbance recording for generators, we strongly urge that the applicability of R3 and R4 for Generator Owners be removed. • R4: The Measure M4, Part (1), should be changed to: “(1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3)”… • R7: “Each Generator Owner shall have DDR data for each BES Element it owns and is notified according to Requirement R5, to determine the following electrical quantities…” This wording is not clear. We suggest using wording, similar to R6, “Each Generator Owner shall have DDR data for each BES Element it owns for which it received notification as identified in Requirement R5, to determine the following electrical quantities…” • R7: In Measure 7, Part (1), we suggest changing to : “(1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations;” This will allow needed flexibility in providing reasonable evidence. • R8: In Measure 8, make the same change as described above in M7. • R9: The Measure 9, Part (1), should be changed to: “(1) documents describing the device specification, configuration, or settings”. • R10: The Measure 10, Part (1), should be changed to: “(1) documents describing the device specification, configuration, or settings”. • Guidelines and Technical Basis Section , Guideline for Requirement R2, two statements are made that are at least unclear, if not contradictory: “SER data for generator breaker operations provides little useful data of generator loading.” “Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers connected to the Transmission Owner’s bus”. Please clarify or revise as necessary.
Individual
David Thorne
Pepco Holdings Inc.
Yes
Yes
Under requirement R11.2, suggest modifying the wording to the following: The recorded data will be retained for a minimum of 10 calendar days.
Individual
Thomas Foltz
American Electric Power
No
R1: The scope for the process in Attachment 1 should be limited to only those BES buses that have local protection systems that serve to protect the connected BES elements. R1: The process for identifying BES buses within Attachment 1 could lead to a breaker protected load bus, with only two BES source lines, being in the “top 10%” of locations that must have DFR/SER. The reason for such a location being in the top 10% would be driven by its proximity to other top 10% BES buses. The Standard should allow for exclusion of such locations, provided they are substituted by the next BES bus in the list. AEP believes this change would allow DFR/SER equipment to be deployed where proper event analysis is truly needed. An alternate approach would be to completely eliminate the top 10% criteria, which would allow industry maximum flexibility in determining the most appropriate location for such installations. R1 & R5: As written, these requirements are single sentences which are five lines in length. With no transitions of thought, they are difficult to read. The

wording should be revised to break up independent thoughts so it reads more concisely. R1 & R5: The notification within 90 calendar days has no reference point. The requirements should be revised to state "… within 90 days of completing the Attachment 1 methodology" or similar wording. R1 & R5: Both requirements state "BES Elements may require…" Why is this a "may" statement? This seems to be in conflict with the beginning statement of the requirement that indicates a bright line identification of what requires monitoring. AEP recommends employing a consistent structure for R1 and R5. The criteria for R1 are contained within an appendix, while the criteria for R5 are contained within the requirement. AEP recommends modifying R1 so that the notified entity has the option to monitor either the local or the remote terminal of the subject Element.
No
While AEP has no disagreement with the Elements as specified in R5.1, the standard lacks clarity in what flexibility if any, the Responsible Entity has in selecting them. For example, the text "may require DDR data" implies some flexibility in that regard, and such flexibility should be made more explicit within the standard. It would be more clear if the minimums provided in 5.2 were provided *before* the Elements specified in 5.1 (essentially a swap of 5.1 and 5.2).
AEP believes that the wording of requirement R11.2 clearly conveys the drafting team's intent that an entity is not required to retain more than 10 days of disturbance monitoring data at any point in time. Unfortunately, this intent is blurred by the Compliance Evidence Retention's opening paragraph and the statement that "The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12… for three calendar years." The Evidence Retention, as written, could be interpreted as requiring an entity to maintain three or more years' worth of SER, FR and DDR data. The issue is further confused by the proposed PRC-002-2 RSAW in which the Evidence Requested and the Compliance Assessment Approach for R2, R3, R4, R8, R9, R10 and R11 indicate that SER, FR and DDR data is required to demonstrate compliance and imply that an entity is required to keep all SER, FR and DDR data within the audit window. AEP believes that retaining years of disturbance monitoring data is overly burdensome, provides little to no benefit to reliability and is not the intent of the drafting team. The standard should be revised to align the Compliance Evidence Retention with the Requirements and to more clearly convey the 10 day data retention requirement. The Implementation Plan includes the following "Entities shall be 100% compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." We agree with this statement, but believe it would be more appropriate to include it within the Standard itself, rather than only within the Implementation. R1: The SDT should clarify who takes the lead role to notify other owners when there are multiple owners of a bus. Presumably it would be the company identified as the owner in the fault model being used but this should be clarified. Also, notification alone should not be sufficient in identifying monitored buses. There should be agreement from all owners that a bus should be monitored before it is included in the monitored list, unless it is in the top 10% which indicates it *must* be monitored. R2: It is unclear from the wording of R2 whether the TO/GO must monitor all circuit breakers connected to an identified bus or only circuit breakers connected to the identified bus that are associated with a BES Element. For example, would a 138 kV circuit breaker for a radial fed station service transformer be required to be monitored if it is connected to a selected bus? In this case, the station service transformer would not be a BES Element. We do not believe it would be appropriate to require SER or DFR data in this scenario, but the standard does not explicitly prevent such an interpretation. We suggest making it clear that the element is *both* connected directly to the BES buses identified in Requirement R1 *and* associated with the BES Elements at those BES buses identified in Requirement R1. R3: The Application Guide implies that GSU leads are not considered lines for this standard. The requirement should be revised to clearly indicate this. Similarly, station service or reserve transformers should likewise be explicitly excluded. R3: The callout for R3 states "The required electrical quantities may either be directly measured or derivable if sufficient FR data is captured". The allowance for derivable methods is specified only in the callout, and is not explicit within the standard itself. This allowance needs to remain somewhere in the standard. Guideline for Requirement R3: We are confused by the exclusion "For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator in case of fault on the transmission system will be captured by FR data on the transmission system." We do not understand how the generation currents could be calculated from the transmission currents for faults on the interconnection. In addition, is it the drafting team's intent to exclude most generating units from fault recording? R12:

We see no reliability benefit in sending all CAP's to the Regional Entity, and recommend revising it in consideration of Paragraph 81. Rather, it should be acceptable to only require the TO/GO to develop and execute a CAP and to make this information available to the RE within 30 calendar days of a request. AEP recommends revising the purpose statement to read "To ensure adequate data is available to NERC to facilitate event analysis of major BES disturbances. AEP recommends establishing only 5 requirements. There should be a requirement for each of the main objectives (establish a data set for FR/SER, establish a data set for DDR, provide FR/SER data upon request, provide DDR data upon request), and a single requirement for repair. AEP recommends modifying R1 so that the notified entity has the option to monitor either the local or the remote terminal of the subject Element. AEP recommends modifying R2-R4 and R6-R11 to clearly exempt data lost due to an equipment failure properly identified per R12. AEP recommends modifying R3 so that only 3 of the 4 currents are required to be recorded. Since the fourth current can be calculated by the other three, there is no reliability impact for recording only three currents.
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
Yes
No
See comments under Question 3
The three-phase short circuit level minimum of 1500 MVA at BES voltage levels is low. As a result, entities must sort through large numbers of buses when only the top 11 would need to be selected. Buses at low three-phase fault current are not typically conducive to disturbance monitoring equipment. For example, a 345 kV bus that carries 3000 amps (normal flow) would be a candidate for PRC-002 even without applying a three-phase fault. It would seem that a threshold of 10,000 MVA is technically justifiable, since most BES stations that have over 10,000 MVA of available three-phase fault current are candidates for being critical facilities that would benefit from disturbance monitoring equipment or already have such equipment installed. This would also reduce the number of buses that the TO needs to review. There is uncertainty regarding the technical justification for the "11" BES buses that is listed in Step 3 of Attachment 1. Requirement R8 does not clearly identify the data storage requirements for DDR with continuous recording capability. A 3-year period of continuous recording data per DDR location is too onerous. DDR continuous recording capability should be a minimum of 10 days per site. DDR recording(s) retained as evidence should strictly be limited to event-triggered recording by a system disturbance and where the RC, RE, or NERC requests data for the event within the 10-day time frame. Requirement R11.4's required conformance with IEEE Standard C37.111-"2013" is too onerous. This Requirement disqualifies the majority of FR and DDR equipment presently deployed. Seminole recommends revising the Requirement to require the use of IEEE Standard C37.111-"1999" or later.
Individual
Scott Langston
City of Tallahassee
No
see response for question 3
No
see response for question 3
TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes

Yes
In both R3 and R4 it appears the applicability is for Transmission Owners and Generator Owners but the GO typically does not own a substation bus, transformer with a low-side of >100 kV, or transmission lines (as a registered entity of GO). We believe Generator Owner should be removed from these requirements. In R5 please consider the following modifications: R5.1.2, bullet 1 – Add "as judged by the Responsible Entities" to the end of the bullet. R5.1.2, bullet 5 – Add "as judged by the Responsible Entities" to the end of the bullet. R5.2.2 – Add "within the past 10 years" to the end of the requirement to provide a reasonable and finite time frame. The NSRF interprets R11.2 to say that NERC/Regions will always submit a request for data within 10 days of an event, so it is not necessary for DME's to hold data longer than that timeframe. As this impacts the memory/storage capability of the equipment we would appreciate clarification as to how the 10 days was determined and if the SDT believes the timeframe is long enough.
Group
Colorado Springs Utilities
Kaleb Brimhall
Yes
Yes
Thank you SDT for your efforts we voted negative for the following reasons: This standard brings 20% of our buses into scope, which means it will bring 20% of just about everyone's buses into scope (some large companies could have hundreds of buses included). Is that really the SDT's intent? It sounded like the SDT is not expecting it to be that big of an impact. The MVA threshold needs to be re-visited to prevent excessive, unmerited impact. We do not believe that it is logical to include a bunch of buses from smaller entities that just barely cross the threshold and then only include the top 20% of companies with buses having orders of magnitude greater short circuit duty. How can the inclusion criteria be modified to make sure that we capture the appropriate points of the system based on actual risk and impact to the BES? The current criteria is too inclusive and too generic - which impacts industry unnecessarily without getting the desired result. Thank You! Bottom line, IMO, the technical basis for this standard is flawed.
Individual
Brett Holland
Kansas City Power & Light
No
See comments at end of form.
No
See comments at end of form.
We suggest that the DMSDT further clarify the Applicability of the Functional Entities in 4.1 by including a statement in the Rationale Box for Functional Entities that when Responsible Entity is used in PRC-002-2, it specifically refers to those entities listed under 4.1. This is a slightly different approach than usually taken in Applicability. Some drafting teams have adopted a convention of hyphenating terms such as 30-, 60- and 90-calendar days. We suggest the DMSDT do the same. Similarly, '30-cycle post-trigger' should also be hyphenated. We also noted that in the redline, step-up transformer was hyphenated in some places and not others. However, in the clean copy of the standard it is not hyphenated. We believe it should be. We suggest modifying the first sentence of Requirement R8 such that it reads: 'Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage.' There are a couple of instances in the 3rd paragraph of the Rationale box for R11 where 10 days is used. We believe this should be 10-calendar days. We suggest the following replacement for the 2nd item under Step 7 of Attachment 1. 'If the list has 1 to 11 BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.'
Individual

Amy Casuscelli
Xcel Energy
Yes
In general, several requirements stacked into one can lead to missed activities/compliance issues, but we defer judgment on this to the NERC Standards Committee review and standards development guidelines.
Yes
We still believe the "Responsible Entity" should be consistent across the Interconnections. We recommend changing this to be the Reliability Coordinator for all Interconnections.
Xcel Energy engineers have conducted a test application of the selection criteria in Attachment 1, and have concerns that some locations are identified but provide little or no value (e.g. situations where fault recording is required for busses at both ends of a short line and one of the busses has only two sources (see diagram provided separately via email to the NERC SDT Coordinator for this standard)). We recommended an ‘exception’ written into the requirements with the Responsible Entity (or RC or Regional Entity) concurrence. In R5 – please clarify if the IROLs are those established by the TP, PC, or RC. (Also note that RC established IROLs may be in the operating horizon with little or no time for entities to actually install equipment). R12 should be reworded to state “...or develop and submit to the Regional Entity...” and end after “...(CAP).” R12 – is it inferred that entities can conduct maintenance on these devices (ie – out of service) as long as they meet the 90 day requirement? If so, consider making that clear.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
No
Note that AECI agrees with the current PRC-002-2 R5.1.2 Bullet#1 wording related to Flowgates, and appreciates this SDT's being thoughtfully responsive to prior comments. FOR: PRC-002-2, R5.1.2, Bullet #5 REMOVE: “or relatively low Available Transfer Capability (ATC)” RATIONALE: AECI believes calculated ATC is based upon many complex factors that are somewhat subjective, primarily Market related, and therefore a technically weak indicator for locating where reliability-related DDR equipment should be located.
FOR: Appendix #1, Step 6, Paragraph 2 REPLACE: “buses with the highest” WITH: “bus with the highest” RATIONALE: Clarity – As this process step seems to yield one identified bus, presumed to fill the void of its successor bullet’s 10% minimum count, the use of “required at” in conjunction with “buses” is confusing. FOR: PRC-002-2, R5.2, Guidelines AECI believes the guideline for 5.2 should provide sample calculations for the number of DDRs required: 1) for an entity having 5999 MW Historical Load, and 2)for an entity having 6000 MW Historical load. While we believe the answer for 1) is only 1 DDR, and for 2) 2 DDRs per R5.2, the Webinar presenter mentioned some expectations for Rounding which introduced uncertainty that the above example could address.
Group
Santee Cooper
S. Tom Abrams
Individual
Karen Webb
City of Tallahassee
No
Please see comment for question 3.
No
Please see comment for question 3.
TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.

Individual
Alshare Hughes
Luminant Generation Company, LLC
Yes
Yes
(1) Requirement R11, subsections 11.3, 11.4 and 11.5 includes prescriptive details regarding data recording and reporting. The goal of the standards development process is to develop Results Based Standards. These items are completely administrative in nature and are not results based. An entity could make a typo in formatting or when naming a file and be non-compliant with the requirement. These requirements should be removed from the standard or relocated to reference documents as described below. (2) Requirement R11, subsections 11.4 and 11.5 reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. Inclusion in a reference document seems to provide a better location to document specific details on requested data and can provide a more effective mechanism for revising these details at a later date in regards to the data reporting. (3) Requirement R11, subsection 11.4 specifically references “IEEE C37.111-2013”. Some older DFRs that effectively capture the needed data may not meet this requirement for the 2013 software update. Software updates may not always be reasonably accomplished with equipment, service contracts or other factors. This specificity is administrative in nature and does not contributed to a results based standard. This version requirement should be revised to allow for any software versions that the entity has access to that supports the recording and report requirements.
Individual
Dan Roethemeyer
Dynegy
No
The DDR requirements for GOs are more prescriptive than other regional Criteria or Regional Standards (i.e. NPCC). Recommend the 500 MVA limit be increased.
Individual
Michael Moltane
ITC
Yes
Yes
ITC feels that the Requirement 10 specification of + 2 milliseconds of Coordinated Universal Time (UTC) is too restrictive for a number of industry wide installed modern microprocessor based relays. These relays have proven to be reliable from a protection, SER, and FR perspective. Additionally, the present PRC-018 standard indicates that a DME’s clock shall be synchronized within 2 ms. ITC agrees the PRC-018 synchronism requirement would be acceptable for SER device clocks but not data. It is recommend that the DMSDT consider changing the tolerance level for breaker status SER to be within 10 milliseconds. This would allow the continued use of these microprocessor based relays. This will be consistent with DMSDT guidance that microprocessor relays are acceptable implementations of SER and FR.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes

These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
No
We agree that DDR data should be obtained for the transmission lines from generation plants as listed in requirement 5.1.2, but not that GOs are the parties that should collect this information. DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data; GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording/storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. DDR data collected on the TO's side of the generation plant battery limits would be the same as that measured on the GO's side, so one could apply the same logic as is stated on p.33 of the standard for FR data, "For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection." Moreover, as regarding assignment of responsibility for monitoring disturbances, such events are more likely to originate in the transmission system (as was the case for the Northeast blackout of 2003) than in generation plants. The SDT emphasized in its discussion of 6/11/14 with the NAGF Standards Review Team that duplication of equipment is not mandated – a GO can contract with its TO to supply the data if the TO has DME at a plant or is willing to add such equipment. We are concerned that the SDT may not have considered the difficulty in negotiating such agreements for the provision of such data or the transfer of compliance responsibilities. A requirement in the standard that TOs must coordinate with generators to provide the data where they own DME at a generation plant would be preferable if GOs have any responsibility under the standard. The least-total-cost approach should be followed in obtaining the expected reliability benefits, and we believe that centralizing DME with TOs makes more sense than splitting the responsibilities between involved entities (TOs) and those who merely hand-over recordings (GOs) for further analysis. We recommend that the SDT perform a cost-benefit analysis of the two approaches before finalizing this standard.
See comments 3a-3c below. 3a. The Guidelines and Technical Basis Section of the standard states in the first paragraph on p.33 that, "SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data." The next section (Guideline for Requirement R2) states however that "Generator Owners are included in this requirement [for SER data] because a Generator Owner may, in some instances, own breakers connected to the Transmission Owner's bus." All generator output breakers connect eventually to the transmission system however, nor is it clear why the aforementioned lack of tripping time reliability for GO sequence-of-events monitoring would apparently apply in some cases (GO SER data mandatory) and not in others (GO SER data not required). 3b. The Guideline for Requirement R3 on p.33 states that "Generator step up transformers (GSU) are excluded from the above based on the following: - Current contribution from a generator in case of fault on the transmission system will be captured by FR data on the transmission system. - For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed. The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data." This seems to fully exclude GOs from fault recording obligations, so why are GOs obligated in R3 and R4 to have FR data? 3c. Comments 3a and 3b above gain emphasis from the circumstance that it is expected that the Guidelines and technical Basis Section of the draft standard will be deleted if and when PRC-002-2 is voted-in and approved by FERC. That is, the logic by which GOs are sometimes in and sometimes out will be even more obscure than it is now. 3d. The requirements for GOs to "have" SER (R2), FR (R3 and R4) and DDR (R7) data are understood to mean that they do not need to own this equipment, and it would do just as well to have an agreement with the TO to fulfill the PRC-002-2 requirements if and where the TO already has DME on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002-2. There should be a footnote saying that "This standard defines the 'what' of DDR, not the 'how.' GOs may install DME or, where

the TO already has suitable DDR, contract with the TO." It would be still better to just drop GOs from the picture, however, per our comments above.
Group
SPP Standards Review Group
Robert Rhodes
Yes
Yes
We suggest that the DMSDT further clarify the Applicability of the Functional Entities in 4.1 by including a statement in the Rationale Box for Functional Entities that when Responsible Entity is used in PRC-002-2, it specifically refers to those entities listed under 4.1. This is a slightly different approach than usually taken in Applicability.
Some drafting teams have adopted a convention of hyphenating terms such as 30-, 60- and 90-calendar days. We suggest the DM SDT do the same. Similarly, '30-cycle post-trigger' should also be hyphenated. We also noted that in the redline, step-up transformer was hyphenated in some places and not others. However, in the clean copy of the standard it is not hyphenated. We believe it should be. In some places in the documentation three-phase is hyphenated and in others it is not. While we think it should be, we encourage the DM SDT to be consistent. 'Disturbance' is defined in the NERC Glossary and depending upon its usage should be capitalized. The DM SDT needs to be consistent with its format. In the 2nd line of M3, insert 'that' in between 'data' and 'is'. In the 3rd line of the 1st paragraph in the Rationale Box for R5, it would be appropriate to use BES rather than spelling out Bulk Electric System. Add a hyphen to 'high-' in the 3rd line of the Rationale Box for R7. This is consistent with usage throughout the rest of the documentation. We suggest modifying the first sentence of Requirement R8 such that it reads: 'Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage.' There are a couple of instances in the 3rd paragraph of the Rationale box for R11 where 10 days is used. We believe this should be 10-calendar days. Also, in the next to last line of the last paragraph 'disturbance recording' is capitalized. It is not a defined term in the NERC Glossary and shouldn't be capitalized. This change needs to be made throughout the documentation. In the 6th line of the Rationale Box for R12, 'entity' should not be capitalized. In the VSLs for R2, insert 'Owner' between 'Transmission' and 'or' for consistency throughout the VSLs for the other requirements. We suggest the following replacement for the 2nd item under Step 7 of Attachment 1. 'If the list has 1 to 11 BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3. Proceed to Step 9.' 'Disturbance monitoring' is capitalized in the Introduction of the Guidelines and Technical Basis Section. Since it is not a defined term in the NERC Glossary, it shouldn't be capitalized. Modify the next to last line of the 1st paragraph in the Guideline for Requirement R1 to read '…voltage and current for individual circuits allow precise reconstruction of events of both…' Change 'disturbance' to 'disturbances' in the next to last line of the 2nd paragraph. In Item 6 on Page 32 (clean version) of the same section, insert 'to those' between 'buses' and 'with'. In the 6th bullet under Item 8 on the same page, change 'Owners'' to 'Owner's'. Hyphenate 'in-effect' in the 1st line of the 2nd paragraph of the Guideline for Requirement R3. Modify the 1st line of the Voltage Recordings section on Page 34 (clean version) to read 'Voltages are to be recorded at applicable BES buses. Note that Requirement R3 calls for the…' Delete the 's' on 'meets' in the 2nd line of the 1st paragraph of the Guideline for Requirement R4. Change 'captured' in the 1st line on Page 35 to 'captures'. In the 2nd line of the same paragraph, set the phrase 'when time synchronized to a common clock' off with commas. Delete the last sentence of the 1st full paragraph on Page 36 (clean version). It is a duplicate. Insert an 'a' between 'after' and 'fault' in the 1st line of the 1st paragraph under Guideline for Requirement R6. Replace 'has' with 'with' in the 3rd line of the 1st full paragraph on Page 37 (clean version). Near the end of that same line, there appears to be an extra space between 'Bus,' and 'would'. Skip a line and hyphenate 'in-service'. Capitalize Real Power and Reactive Power here and in the last paragraph before Guideline for Requirement R7. Add a hyphen to 'high-' at the end of the 1st line under Guideline for Requirement R7. Hyphenate 'short-term' in the 2nd line of the 1st paragraph under Guideline for Requirement R9. In the 4th line of the 2nd paragraph, insert an 'a' between 'in' and 'sampled'. Capitalize 'Requirement R1' and 'Requirement R5' in the 3rd line of the 1st paragraph under Guideline for Requirement R11. Delete the 'a' in front

of ‘Day 1’ in the 6th line of the 3rd paragraph under Guideline for Requirement R11. Insert an ‘and’ and delete the ‘it’ in the 2nd and 3rd lines of the 2nd paragraph on Page 40 (clean version). That portion of the sentence should then read ‘...Transient Data Exchange and is well established in the industry.’ Split the 2nd sentence of the 3rd paragraph on Page 40 (clean version) into two sentences such that it reads ‘...Naming Time Sequence Data Files. The first version was approved in 2007.’ In the 4th line of the 3rd paragraph on Page 40 (clean version) replace ‘was’ with ‘were’. Hyphenate ‘out-of-service’ in the paragraph under Guideline for Requirement R12. Also, there appears to be an extra space between ‘develop’ and ‘a’ in the 10th line of the same paragraph.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Individual
Chris Mattson
Tacoma Power
Yes
Tacoma Power disagrees with the need for this standard. However, assuming that this standard will likely proceed to approval, Tacoma Power takes no exception to merging these requirements.
No
It is unclear what requirements for DDR data changed. The redlined version has only superficial changes to Parts 5.1 and 5.2. Tacoma Power has some concern about the fourth bullet under Part 5.1.2: “Interfaces between Balancing Authority Areas.” While this is only one guideline that the Responsible Entity should (not must) consider, it could potentially place disproportionate burden on entities with a relatively small Balancing Authority Area.
Tacoma Power disagrees with the need for this standard and believes there are more cost effective alternatives for acquiring the data necessary for event analysis. However, assuming that this standard will likely proceed to approval, we are providing both comments for improving the draft standard and an explanation for why we believe this standard is not the appropriate method to address the perceived needs. a. Under Measurement M3, change “...of FR data is...” to “...of FR data that is...” b. Under Measurement M11, change “...evidence (electronic or hard copy) data...” to “...evidence (electronic or hard copy) that data...” c. What if FR, SER, or DDR equipment is taken out of service for maintenance and/or testing. Could this result in an automatic violation of Requirement R11, Part 11.2? Or, should this be treated like a failure under Requirement R12? d. In Attachment 1, Step 7, for cases in which the list has 11 or fewer BES buses, change “...at the BES buses with...” to “...at the BES bus with...” e. Please confirm that only the channels that trigger need to be provided upon request and that no cross-triggering between FR or SER is required. f. Requirements R3 and R4 should require the capability to record data rather than requiring data. g. The VSLs for Requirement R10 should be based on the number of missed electrical quantities rather than the number of BES buses. Otherwise, please provide guidance on how a substation with several relays correctly time stamped but one relay with an incorrect time stamp should be treated. h. Requirement R10 should be modified to have SER timestamping to +/- 40 milliseconds while maintaining the FR and DDR timestamp of +/- 2 milliseconds for two reasons. First, the breaker position indication using 52a or 52b contacts can be different than the main contacts opening and ultimate current interruption by more than 2 cycles. Typical, 52a vs 52b contacts are at least ½ of a cycle apart. Timestamping the relay input to 2 milliseconds will not actually indicate the state of the power system. Second, SEL 300 series relays timestamp SERs to the nearest quarter cycle, so a large number of installed relays would not meet the requirements for SERs. These relays do timestamp the FR to the specified accuracy, just not the SER. Alteratives to this draft standard: The 2003 outage report outlined major deficiencies with event recording, but the data recording technology has dramatically changed in the last decade. Even though no standard was in place specifying data recording, utilities have been installing GPS time stamped event recording based on

business drivers. As outlined during the CEAP report, the labor for event report alignment was reduced from 4,400 person-hours for the 2003 outage to only a week for the 2011 southwest outage. Although further reductions in event analysis SME hours would result from this standard, the compliance SME hours would dramatically increase and result in overall higher costs. As outlined in the CEAP report, most utilities already have event recording in place, or are going toward recording as part of multifunctional equipment installations. Therefore, ignoring automated event collection, the only costs that should be considered are due to the increment burdens of documenting compliance with this standard. Instead of this standard, we believe that a NERC guidance document on event reporting best practice would be equally effective while requiring very little compliance burden. In other areas, NERC is moving away from standards that require zero defects in high volume tasks. This standard requires 100% accurate time stamping of 100% of a small portion of elements, but then ignores 80% of BES buses. On a voluntary basis, we have approximately 50% of elements monitored. Thus if we supplied only the event reports required by the standard, the coverage of our system would go down dramatically. In order to meet the zero defect policy of this standard, we will have to redirect efforts from actual event analysis to documentation of event recording capability. If data recording is implemented as a standard instead of a best practice guideline, it sets the minimum bar instead of the optimal goal. Most utilities already have at least a marginal level of recording capabilities. We would prefer NERC to aim higher. The best event records occur when all data channels at a substation are recorded for a trigger on any channel for any kind of transient, including frequency or overvoltage. This level of recording is impractical to require as a standard but is already in place for many utilities. For an enforceable standard, we agree that undervoltage & current are the only reasonable triggers to require. We are concerned that the SDT appears to have based installation cost assumptions on the premise of using data stored locally on relays. If this is an enforceable standard with a zero defect requirement, utilities are in essence forced to automated event collection from relays in order to guarantee zero defects. This automated event collection then brings in large costs for communications, and for applying CIP standards to those communications. If this were a best practices document, or allowed some data gaps, local relay storage would be a reasonable assumption.
Individual
John Brockhan
CenterPoint Energy Houston Electric, LLC
Yes
Yes
1) Regarding R2, CenterPoint Energy believes that breaker open/close operations obtained from the EMS system time-stamped based on RTU scan is adequate SER data for the initial stages of event analysis before detailed disturbance data is obtained from the FR and DDR data that is ultimately required for the actual event analysis. Therefore, CNP recommends removing SER data from R10. 2) Requirement R3 states "...shall have the following FR data to determine the following electrical quantities for each of the BES Elements they own connected to the BES Buses identified in Requirement R1:". CenterPoint Energy believes this language causes confusion with regard to "determining" phase-to-neutral voltages for each phase of each specified BES Bus as required by Part 3.1. The BES Bus voltage can be "determined" by measuring/recording each phase-to-neutral voltage of each line, or by measuring/recording each phase-to-neutral voltage of a smaller subset of lines connected to a BES Bus. The Guidelines and Technical Basis Section describe measuring voltages of "each" line. For entities that are using dedicated fault recording devices, channel capacity can be an issue. In some installations, voltages from 2 or more lines, i.e. a subset of the total number of lines connected to the BES Bus, can be recorded to provide adequate phase-to-neutral voltage FR data for system disturbances obviating the need to record each phase of each line at the recorder. CNP recommends that the DMSDT reconcile the Guidelines and Technical Basis Section language with the Part 3.1 language such that BES Bus voltages can be "determined" by measuring a number of line voltages based on engineering judgment.
Individual
Kayleigh Wilkerson
Lincoln Electric System

Per Attachment 1, Step 1 utilities are instructed to “Determine a complete list of BES buses that it owns.” A complete list of BES buses could include tap buses feeding radial load where there would be no BES circuit breakers or relaying and therefore no ability to gather the data pertinent to this standard. The SDT response to LES’ previous comments stated that, “If a tapped substation was not modeled in a system study as a bus then it would not be considered a bus.” If this is the drafting team’s intent, it should be clearly stated in Step 1 that tap buses with no BES breakers or relaying are not to be included. Doing so eliminates any possible confusion associated with whether a bus has been included in a system study. Whereas a Planning study model may not include these buses, a System Protection study model would in consideration that non-BES transformer relaying at the tap has to be coordinated with relaying at adjacent substations. R11.2 specifies “The recorded data will be retrievable for the period of 10 calendar days preceding a request.” For clarity, LES suggests restating R11.2 as follows: “The recorded data will be retrievable for the period of 10 calendar days following the date that the data was recorded.” Wording it this way ensures that the 10 calendar day timeframe starts on the day that the data was recorded. If left unchanged, the existing statement would tie the 10 day timeframe to the date of the request which makes the timeframe indefinite given the fact that the requesting entity has no time limit on when a request can be made.
Group
SERC Protection and Controls Subcommitee
David Greene
Yes
No
(1) R 5.1.2. Still seems open ended for us. The following bullet points under this requirement give reasons for concern: • Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection • Interfaces between Balancing Authority Areas • Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC) DDR are applied for stability reasons, so thermal violations, and low ATC are not valid justification. (2) Depending on how our Planning Coordinator interprets these points, we could still be put upon to install an indeterminately large number of PMUs. This language *is* a step in the right direction from the previous draft of the standard, where "all permanent Flowgates" required DDR equipment, however, our preference would still be to delete R 5.1.2 from the standard. (3) If 5.1.2 is retained, please add a section 5.3 “The number of BES Elements need not exceed one per 1000 MW of its historical peak system Demand.” This provides sufficient coverage in the Responsible Entity’s area and encourages the RE to be ‘responsible’ in applying the 5.1.2 guidelines. (4) Some software vendors do not presently have the full capability as described in Requirement 11 implemented in their equipment or DME application software. This could require change out of the existing equipment. (5) Please clarify the 3rd paragraph of Rationale for R5 by adding ‘only one’ so its consistent with Guidelines and Technical Basis section page 36:’For “major transmission interfaces” with the exception of HVDC, the DDR data is to be captured for only one BES Element, and, is obtainable from one terminal (either end) of an Element.’ Also add: ‘If the BES Element has multiple owners, each TO and / or GO will need to agree which owner will have the DDR data, and the other owners can refer to this agreement as their means of meeting their obligations.’ (6) Please add ‘If the BES Element has multiple owners, each TO (and / or GO, as appropriate)will need to agree which owner will have the DDR data (or equipment, as appropriate), and the other owners can refer to this agreement as their means of meeting their obligations.’ In the rationales for R6, R7, R8, R9, R10, R11, and R12 to be consistent with R5 and cover tie line Elements. Similarly, M6 through M12, add the option that for BES Elements with multiple owners, the TO / GO can provide an agreement stating which owner is responsible for the DDR data. (7) The standard should include direction if agreement between entities cannot be reached i.e. “In cases where agreement between entities cannot be reached, the TO/GO that necessitates DM capability is ultimately responsible for the equipment and any /all requirements.”
The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Group

JEA
Thomas McElhinney
The 1500MVA threshold is too low and needs to be increased.
Group
ISO RTO Council Standards Review Commitee
Greg Campoli
No
We agree with the merging of R2 into R1, but not the revised R5 which combined R6 and R7. Please see our comments under Q2, below.
No
Please clarify in R5 whether the first use of the term “BES Elements” is intended to be used here. It appears the intent is that the responsible entities notify all owners of the BES facilities connected to the BES Buses which they have identified. In that case, that term should be “BES Buses” or both BES Elements and BES Buses. We are concerned that the last bullet in Part 5.1.2 may be interpreted to include congestion as it relates to commercial/economic use of transmission interfaces. The term “significant Flowgates” should be limited to only physical/electrical constraints and not congestion that can be mitigated by market mechanisms. Part 5.1.4 needs to clarify whether BES Elements associated with the Interconnected Reliability Operating Limit should include only the monitored element or the contingent element or both. The Rationale for R5 should include the technical reason why the “Responsible Entity” is the applicable entity for identifying buses/elements for DDR events. As stated in the Background Information of the Comment Form, the SDT states the PC or RC has the overall view of the BES for DDR. This explanation should be included in the standard. R5 is also confusing in what is the requirement for BES Element owners which have been identified as needing DDR. We recommend the following changes to ensure the DDRs are applied on the proper BES Elements: “ Each Responsible Entity shall (i) identify BES Elements for which dynamic disturbance recording (DDR) data is required, (ii) notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements WILL require DDR data upon request of the Responsible Entity, and (iii) reevaluate the identified buses at least once every five calendar years. “ We are also concerned that this requirement envelopes 3 distinct and mutually exclusive requirements, each of which apply to distinct registered entities and each having different measures. This should be separated into three requirements which will also make the measures for VSL and VRF more applicable. The distinguishing of requirements for clarity in applicability and measurement should be included as an element of the “Quality Review” prior to industry comment posting. R5.1 – The BES Elements that require monitoring shall include the following… R5.2 – The BES Elements that require monitoring in each Responsible Entity’s area shall include a minimum of… R5.1.4 requires monitoring BES Elements associated with IROLs. The requirement should only apply to IROLs that are voltage or stability limited: “One or more BES Elements associated with IROLs that are based on voltage or stability performance.”
Attachment 2: acceptable states are OPEN or CLOSE but other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also commonly used. The format should allow for regional variations in terminology. Otherwise, it could become time consuming for TOs and GOs to provide the SER data.
Individual
Chris Scanlon
Exelon Companies
No
Exelon does not agree with the SOE/FR requirements as written but not because of the merging of the R2 and R1 requirements. We believe that there needs to be a streamlined process for entities that are modernizing their system. The SOE and FR portions of this standard are very close to 100% burden to entities that are utilizing modern microprocessor relays connected to GPS clocks for T-lines on their system as a standard. The proposal does not account sufficiently for technical changes that have occurred over the last ten years. The Attachment 1 process is overly burdensome for entities modernizing their systems. An alternative to the attachment 1 process is for an entity to

identify that 40% of its BES transmission lines (transformers need not be monitored if lines are monitored) include FR and SER capability. This would be easy to demonstrate as these types of lists are readily available already. Additionally, we believe the reference to BES Elements / Busses needs clarification. We also object to the TO having the responsibility to notify others of their need to comply with a NERC standard, "notify other owners of BES Elements connected to those BES buses".
Yes
No Commnet
R1: See comments to question 1. R2: It is not necessary to monitor circuit breaker auxiliary contacts to figure out when a circuit breaker opened or closed. Loss of current can be monitored in a fault recorder. This requirement puts a high burden on identifying print #s to show circuit breaker auxiliary contacts are connected to relays with SER capability. This effort is just not necessary based on our experience investigating thousands of operations over the years. The drafting team should eliminate this requirement or modify it to clearly state that cessation of current can be used to determine when circuit breakers open. R3: T-lines are exposed to a much higher number of faults/operations than T-transformers. Thus, modernization of T-line protection provides the greatest increase to reliability by a large margin. Having modern relays on T-lines allows for deducing current in transformers if necessary. The drafting team should concentrate on lines rather than transformers as the industry is doing. The drafting team should remove transformers from R3 since this information can be deduced from line monitoring or change R3.2.1 to state Transformers… “only when sufficient line monitoring is not present to derive transformer quantities”. R4: No comment, previous changes made by the drafting team addressed our concerns. R5: No comment, previous changes made by the drafting team addressed our concerns. R6, R7, R8: No comment. R9: The drafting team should eliminate requirement 9.1 unless they are aware of a significant portion of the industry installing equipment that doesn’t meet this requirement. To our knowledge, the main manufacturers of this equipment all easily exceed this requirement. R10: The drafting team should eliminate the requirement of within +/- 2 msec of UTC unless they are aware of a significant portion of the industry installing equipment that doesn’t meet this requirement. To our knowledge, the main manufacturers of this equipment all easily exceed this requirement. R11: No comment. R12: We’re using microprocessor relays for FR and SOE capability. They are tested under PRC-005 and alarmed upon failure. We should not have to keep track of every relay that fails on the system that we fix or replace for this standard. We have plenty of incentive to keep our relays working already and we don’t run with failed relays for 90 days. Hence, there is no need for R12 and it should be eliminated. It is 100% burden, a complete waste of engineering resources, and hence a detriment to overall reliability. If the drafting team will not eliminate this requirement, it should be re-worded such that it is very clear that we do not need to keep track of failures that are rectified within 90 days. We should not have a compliance burden to prove that we fixed something in 2 days. An overall comment is that we believe this standard is not required for FR and SOE. These functions are built in to modern relays being adopted industry-wide already. All the requirements related to FR and SOE should be eliminated and the standard written to address DDR only. It is even arguable that this standard is required to promote DDR capability as the widespread use of synchrophasors including their storage has greatly expanded since 2003.
Individual
Oliver Burke
Entergy Services, Inc.
Yes
No
We agree with the revised DDR location criteria reducing the number of monitored BES Elements and appreciate the DMSDT efforts to address that issue. However we are still concerned about the potential for an unnecessarily excessive number of required DDR locations with regard to Flowgate applications. We believe the proposed minimum criterion of “One additional BES Element for each additional 3,000 MW of its historical peak system Demand.” does specify a reasonable lower threshold which provides adequate wide area coverage and also believe there should be a similarly defined upper threshold on the number of DDR Flowgate (or DDR total) locations required. Suggest DDR Flowgate location criteria be revised to specify no more than twice the adequate minimum number of locations as follows: “Stability related interfaces or other significant Flowgates in the

NERC Book of Flowgates for the Eastern Interconnection (prioritized by the Responsible Entity with area coverage considerations and with a total of no more than one BES Element per 1,500 MW of its historical peak system Demand),"
Entities with a significant number of DDRs and have DDRs which include installations where manual data retrieval is necessary should be allowed more than 30 days to collect, format, assemble and review data for submittal. Add provision for a data request submittal extension such as "R11.1 The recorded data will be provided within 30 calendar days of a request unless an extension is granted by the requesting authority."
Individual
Bill Fowler
City of Tallahassee
No
see comment for question 3
No
see comment for question 3
TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.
Individual
Don Schmit
Nebraska Pubilic Power District
No
R1 should have some explanation for what the implementation/installation deadlines are for newly identified BES buses as part of the 5 year review. R1 states "reevaluate the identified BES buses at least once every five calendar years", should this read "reevaluate all BES buses at least once every five calendar years"? It seems that new buses may be added and existing buses in the required locations for FR may get dropped down the list and become discretionary. R2 rational states "time stamped according to Requirement R10 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance." Since relays and FR recorders often use separate clocks consider changing "common clock" to "time synchronized clock". R7 states: "Each Generator Owner shall have DDR data for each BES Element it owns and is notified according to Requirement R5". Should this read "Each Generator Owner shall have DDR data for each BES Element it owns as notified according to Requirement R5" instead? It seems a bit confusing how to read this requirement. It could be read that the GO "shall have DDR data for each BES Element it owns". Consider if this requirement can be clarified or restated.
No
For R5 if the Responsible Entity is slow in notifying owners where DDR data is required does this force the owners to meet the same implementation deadlines or can they extend the deadlines by the same amount of time the RE was late in getting a notification out to the owners? I bring this up because the BES owners will not have any control over the RE schedules but could be subject to shorter implementation deadlines. In addition, since there is some open ended latitude in the ability of the Responsible Entity to identify locations for DDR it is possible that large number of locations could be identified to install DDR in some areas. If this were to occur would there be a possibility for the BES owners to request additional implementation time to become compliant? Consider if some clarification could be added. One option might be to have criteria in 5.1.2 less open ended without any latitude.
It appears, for example, GSU 13.8kV generator buses that exceed the 1500MVA fault current level should be in the bus fault list for FR evaluation. If this is correct they are often ungrounded systems. Can the FR voltages and currents be monitored on the high side of GSU or a tie transformer with a BES tertiary reactor? It seems unclear what currents would be required to monitor as there would not be any ground current at these types of locations/buses if the ungrounded low side must be monitored. R3 and R4 don't specifically mention GSU transformers, GSU low side buses or BES tertiary buses which tend to be ungrounded systems. Can the drafting team clarify that for tertiary or GSUs where the generator bus (for example 13.8kV) is identified in the list of fault buses that it

would be acceptable to monitor the voltages and currents on the high side of the GSU or tie transformer? If not, clarify that only the three 13.8 line to ground voltages or 13.8kV line to line voltages are required but not the currents or at least not the ground current. Note that the option of line to ground or line to line voltages is suggested above. Some ungrounded buses may not have line to ground voltages. This may be a concern for some utilities. It seems a bit odd the DDR would be allowed to be on the GSU high side yet still require FR data using the generator bus side voltages as the standard appears to read. R7 seems to address the high or low side requirements better for DDR but clarification for what is required for GSU and generator buses for FR would be helpful since they are often ungrounded systems. For R11 it states: “Each Transmission Owner and Generator Owner shall provide all SER, FR, and DDR data for the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 to the Reliability Coordinator”. Consider clarifying this wording since it appears to require DDR data is required for R1 to be provided to the RC. R10 also appears to have this concern as well. DDR data is not required by R1, but through the use of the word “and” in R10 and R11 it appears that DDR recording may be necessary on these buses. R12: Is the CAP required to be submitted to the RE or is it upon request similar to the records? This requirement seems like it would be difficult to audit since it would be tracking work on a utilities system. I wonder if the RE is prepared to monitor this information. If they do plan to monitor this is there any other process format or forms necessary or is it understood to be an informal case by case transmittal of CAP status?
Individual
John Pearson
ISO New England
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
We agree with the concept of the requirement, however, we suggest moving the methodology for selecting DDR locations described in 5.1 and 5.2 to an attachment and not include it within the text of the requirement itself (similar to the SER/FR bus selection methodology in Attachment 1 for R1).
1. R1 VSL – The percentage and time basis language in the first two parts of the VSLs are confusing: it’s unclear what the percentages are referring to and what time period the assessment is being measured to. Also, the term assess is not used in the requirement or Attachment 1. The third part of the VSL is clear. Suggestion to change VSL language for the first two parts to the following language across all severity levels in the table: “The Transmission Owner identified BES buses as directed by Attachment 1 for more than 80% but less than 100% of the BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement 1 but was late 30 calendar days or less for the once every five year requirement.” 2. R5 VSL – The percentage and time basis language in the first two parts of the VSLs are confusing: it’s unclear what the percentages are referring to and what time period the assessment is being measured to. Also, the term assess is not used in the requirement or Attachment 1. The third part of the VSL is clear. Suggestion to change VSL language for the first two parts to the following language across all severity levels in the table: “The Responsible Entity identified the BES Elements as directed by Requirement R5 for more than 80% but less than 100% of the BES Elements included in R5.1. OR The Responsible Entity evaluated the BES Elements as directed by Requirement 5 but was late 30 calendar days or less for the once every five year requirement.” 3. For R3.1 – Attachment 1 states that a ring bus or breaker-and-a-half bus are considered as a single bus. Will the SDT please clarify does this mean that in a ring or breaker-and-a-half substation, only one bus needs to monitored for R3.1? 4. For R11 – We suggest moving the language describing specific formatting requirements in R11.3 through R11.5 to the Guidelines and Technical Basis section of the standard as it is administrative in nature and not performance-based. 5. For R12 – Has the SDT discussed having the entity reporting FR/SER/DDR failures report to the Responsible Entity as well as the Regional Entity, so that the Responsible Entity can look at possible alternative methods to monitor the Elements identified per R5? There may be a reliability gap if the Responsible Entity is not notified due to no requirement for the GO or TO to do so. 6. R11 VSL - The Requirements refer to days and the VSL language refers to percentages. We

ask the SDT to confirm that the interpretation of R11 VSLs below is correct. If so, we suggest changing the VSL language to the language provided below. If not, please provide the correct interpretation and possibly revised language to help assure there aren't inconsistencies in compliance and enforcement application. Lower VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 9 days but less than 10 days of the requested data. Moderate VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 8 days but less than 9 days of the requested data. High VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 7 days but less than 8 days of the requested data. Severe VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided less than 7 days of the requested data.
Group
Seattle City Light
Paul Haase
No
R1 does not meet NERC principles for world-class Standards, because it includes three separately audited control activities in a single sentence: (1) identify buses, (2) notify others of buses, (3) reassess every five years. If this draft Standard is deemed necessary, Seattle recommends rewriting R1 to include three subrequirements as follows: R1. Each Transmission Owner shall: R1.1 Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1. R1.2 Notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days that those BES Elements may require SER data and/or FR data. R1.3 Reevaluate the identified BES buses at least once every five calendar years. In addition, the draft Standard does not clarify required actions should the five-year reassessment identify a different selection of buses for which monitoring now would be required. Seattle suggests that an implementation period be identified for installing SER and FR equipment for newly identified buses similar to the implementation time for the initial implementation of the Standard. Likewise, the Standard does not clarify how newly constructed buses are handled. Seattle suggests that that they be evaluated at the next 5-year reassessment, rather than individually as they are brought on line.
No
As for R1, R5 does not NERC principles for world-class Standards, because it includes three separately audited control activities in a single sentence: (1) identify Elements, (2) notify others of Elements, (3) reassess every five years. If this draft Standard is deemed necessary, Seattle recommends revising the first paragraph of R5 to include three subrequirements as follows: R5. Each Responsible Entity shall: R5.1 Identify BES Elements for which dynamic disturbance recording (DDR) data is required R5.2.Notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements may require DDR data R5.3 Reevaluate the identified buses at least once every five calendar years. And then renumber the remainder of the requirements to conform: 5.4 The BES Elements shall include the following: 5.4.1 Generating… In addition, the draft Standard does not clarify required actions should the five-year reassessment identify a different selection of Elements for which monitoring is required. Seattle suggests that an implementation period be identified for installing DDR capabilities for newly identified Elements similar to the implementation time for the initial implementation of the Standard. Likewise, the Standard does not clarify how newly constructed buses are handled. Seattle suggests that that they be evaluated at the next 5-year reassessment, rather than individually as they are brought on line.
Seattle appreciates the efforts of the Drafting Team to respond to comments received following the initial posting of this draft Standard. However, Seattle fundamentally disagrees with the approach proposed by draft PRC-002 for several reasons. First, the proposed Standard requires an entity to establish at least 43 new controls to meet the compliance assessment approaches identified in the draft RSAW, and this figure does not consider the dozen or additional controls required to ensure all Attachment 1 steps are met. For context, consider that approximately 4-5000 controls are required to meet the entire body of NERC Standards. As such proposed PRC-002 represents a 1% increase in the overall compliance burden on the electricity enterprise. Entities will be required to monitor performance of minor activities, and auditors likewise will be required to examine performance. Seattle does not believe the reliability benefit offered by this Standard warrants this new compliance

burden. Indeed each requirement of PRC-002 is identified as “Lower” for violation risk factor (the lowest rating possible), indicating that the drafting team does not consider any requirement of the Standard to have a critical impact on BES reliability. Rather this Standard supports long-term operational improvements in the BES. Seattle believes such improvements are important and supports a reasonable approach to disturbance monitoring, but does not support the complex, over-engineered Standard. The bus screening process is an example of a process that needs to be simplified. The rational does not seem to be well thought out and is certainly not easy to explain and implement (worse than the FERC Order 754 exercise that industry recently participated in). The attached Excel spreadsheet and the directions for completing it are very cumbersome and inefficient--a lot like trying to fill-out a Federal Tax form. Instead of giving an entity the metrics to be achieved, this approach attempts to create a cookbook format where data needs to be entered in one part of the spreadsheet, and then subtracted out in another part of the spreadsheet. Seattle believe appropriate and reasonable a general requirement to have disturbance monitoring, but believes the technical requirements for data type, frequency of sampling, and so forth would be better handled in a criteria or guideline document. Once such requirements are codified as federal law it is cumbersome and lengthy process to change them, yet all are aware how fast technical change has occurred in the area of disturbance monitoring. Moving the technical requirements from the Standard to a guidance document likewise would significantly reduce the compliance burden associated with the draft. Finally, Seattle requests technical justification by established for continent-wide application of a 1500 fault MVA threshold. Once established in a Standard, a technical justification will be required for any change; as such technical justification should be provided beforehand to establish the value as correct and appropriate. This value may be correct and appropriate for the NPCC area, but has not been justified in other regions. It may well be correct and appropriate, but a justification has not yet been provided.
Group
Florida Municipal Power Agency
Frank Gaffney
No
see question 3
No
see question 3
While FMPA appreciates the efforts of the SDT to address many of the specific comments received, FMPA’s position remains that a standard is not justified for Disturbance Monitoring. We believe that Disturbance Monitoring is better addressed through guidelines than through a standard. The system has changed a lot over the last 10 years since the Northeast Blackout of 2003 and we can gain much more information now from microprocessor based relays and phasor measurement units (PMUs) prevalent throughout the system. The justification for this standard is primarily based on the decade old Blackout Report and does not take into account the changes in system equipment since then. This justification was highlighted by the SDT’s response to FMPA’s prior comment about a standard not needed. SDT Response: “(1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:…” Additionally, it should be noted that in the Executive Summary of the Cost Effectiveness Analysis Process (CEAP) Pilot for this project, the following statement was made: “The majority of CEA respondents believed the standard’s potential immediate reliability benefits were minimal.” So, with this CEAP observation along with the low approval rating of 43.29%, there is clearly some significant stakeholder concern with the justification for this standard. In light of the Paragraph 81 Project, the industry is supporting reducing and consolidating the amount of requirements. This standard meets several Paragraph 81 Criteria used to identify requirements for retirement including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. There are 12 requirements and over 20 sub-requirements in the current PRC002-2 draft. The amount of detail is unnecessary and poses a serious compliance burden on registered entities. While we do not believe the standard is needed, we strongly recommend that if this project goes forward, that the drafting team revise this standard to two or three requirements. We point out that the NERC Rules of Procedure have a detailed section on Disturbance Response Procedures – Appendix 8. While we recognize that the SDT has limited latitude in eliminating a project or veering from the SAR, we suggest that the Standard Committee

revisit the justification for this standard and at a minimum review the scope and prescriptiveness of the detailed requirements in light of the Paragraph 81 guidelines.
Individual
Gul Khan
Oncor Electric Delivery LLC
Yes
Oncor supports combining identification and notification into one requirement as done in the latest draft.
No
Oncor recommends an audit curtailment be added to the DDR requirement similar to what is used in Attachment 1 for the FR's and SER's.
General: It is understood the Rationale Boxes will be retained but relocated to the "Guidelines and Technical Basis Section" of the Standard. If the "Guidelines and Technical Basis Section" cannot be used as compliance validation to auditor(s), it is imperative the requirement language be paired to the alternatives specified in the Rationale language. Oncor identified several instances where the Rationale Boxes provided much needed clarity to the Requirement itself. Incorporating the Rationale/intent language into the Requirement or Measurement itself would further clarify the Requirements resulting in a clear and mutual understanding for both the Registered Entity and the auditor(s). Therefore, Oncor recommends the DMSTD review the Requirement/Measurement language and the corresponding Rationale language to ensure there are no gaps. Specifics are provided below: R2: Legacy FR equipment installed before the Standard effective date may not be capable of embedded SOER. R2 does not afford the same caveat for older equipment where SOER is required that R8 provides for older equipment where DDR is required. Language should be added to R2 providing the option to utilize FR digitals to monitor circuit breaker position for required circuit breaker position monitoring. R1 and R5: The Implementation Plan includes specific references to timeframes for becoming fully compliant with the locations lists after approval of the standard, but the Requirement language itself does not include post-implementation "5 year re-evaluation" compliance timelines for the required reassessments. "Re-evaluation time frame implementation" language should also be included in the affected Requirements to prevent any disparity following the initial implementation and departure from the Implementation Plan. R3 and R6: A Rationale should be added that the required "electrical quantities can be determined (calculated, derived, etc.)" to R3 and R6 as described below: • The R3 Rationale explains the method of deriving electrical quantities. The language of R3.1 does not reflect the intent described in the Rationale. Specifically, whether locations where busses are effectively tied together, such as on ring or breaker-and-half bus configurations, can derive the required phase-to-neutral voltages by monitoring a minimum of two of each Phase-to-Neutral voltages, from either line terminal or bus potentials. In a typical large switching station, this could eliminate costly retrofits to literally provide all three phase-neutral voltages for "each line or bus." • The language of R6.3 does not specify the method used to provide "Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required." If a single phase voltage and current are collected for R6, is it acceptable to calculate power flows expressed on a 3 phase basis derived from single phase quantities? Allowing calculated power flow would prevent costly retrofits to literally provide 6 dedicated analog traces for each Element required to have a DDR. R10: The "Rationale for R10" language, "Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset." Hence, requested records must be supplied in UTC format, but the collected and stored format do not. Similar to the "R3 and R6" comments above, the Requirement 10 and/or M10 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding. R10: Additionally, the "Rationale for R10" language should provide a caveat to allow for manipulating event records to UTC for equipment that is synchronized but cannot time-stamp with UTC as the reference. This would be similar to the "or derived" language suggestions to Requirements R3 and R6 which would allow for legacy equipment to meet the standard as well as allow for the time-alignment for multiple FR/SOERs as M11 evidence. Similar to the "R3 and R6" comments above, the Requirement 10 and/or M10 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding. R11: (Requirement 11.4) If relays meet the requirement of a DDR, the language of R11.1 or M11 should specify that synchrophasor data is acceptable for DDR

analysis. Relay Synchrophasor data is not compatible with the legacy COMTRADE format. R11: (Requirement 11.5) Additionally, add "Rationale for R11" language, "Collected and stored data does not need to follow the "C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME)" file naming format. The data provided pursuant to a data request must be provided in the C37.232 file naming format. Similar to the "R3 and R6" comments above, the Requirement 11.5 and/or M11 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding.
Group
ACES Standards Collaborators
Brian Van Gheem
No
We concur with the SDT's observation and rationale that "the requirement for DDR data for identified BES Elements…is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis." We feel that industry is not only capable of identifying the number of devices from this experience, but also where these devices should be located for dynamic disturbance recording, sequence of events recording, and fault recording purposes. We believe this standard should require an entity to generate its own methodology to make these determinations and how often. We feel the method proposed for selecting BES Elements is too broad and could be subject to interpretation from auditors when not properly followed. We also have concerns that the SDT has not identified a transition period in the standard when a Reliability Entity identifies or receives notification that they are then required to install a recording device. The only transition period the SDT has accounted for is what the SDT listed in the implementation plan and based on the effective date of the standard.
No
We disagree with the identification of BES Elements and the minimum BES Element criteria identified by the SDT. We feel that industry is capable of identifying the number of dynamic disturbance recording devices, "based upon [its] experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis." We believe this standard should require an entity to generate its own methodology to make these determinations and how often.
(1) We applaud the SDT's decision to remove the standard-only definitions provided in the previous draft revision. We also approve of the SDT's step to reduce the overall number of requirements listed in this standard. (2) However, we disagree with the SDT's claim that this standard addresses the "what" of data collected and not the "how" the data is collected. The costs of installing new equipment for the purposes of disturbance monitoring could be significant for some of our members. Moreover, industry has already benefitted from the DOE grants to install PMUs and would continue to benefit from these types of financial incentives for continual situational awareness. In its Consideration of Comments posted May 9, 2014, the SDT rebutted our previous submitted comments with references to the 2003 Blackout in the Northeast. However, it was through these financial incentives, that sufficient data was available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California Outages. As stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, "PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP)." Moreover, the resulting report identified that no additional standards were necessary because of this event. We suggest NERC should develop a Reliability Guideline on this topic instead of a standard, as we do not see the cost benefit or justification to allocate resources for an issue that is not a high priority for reliability, such as cyber security. (3) We continue to have concerns that the SDT has not identified a transition period in the standard when a Reliability Entity identifies or receives notification that they are then required to install a recording device. The only transition period the SDT has accounted for is what the SDT listed in the Implementation Plan and based on the effective date of the standard. (4) We disagree with the previous response to our comments from the SDT, as cited in its Consideration of Comments posted May 9, that "to facilitate expeditious and reliable data capture, it is necessary to stipulate the data formats necessary for efficient data analysis". We feel the SDT could incorporate such stipulation in a separate technical specification or even included as reference within the standard. We feel the technical specifications listed in Requirements R8, R9, R10, and R11 would further strengthen this case, and not subject registered entities to possible

violations for every part of these requirements. We feel that technology has significantly improved since the 2003 Northeast Blackout, as manufacturers and industry have supported the need to align such devices on a common frame of time and develop related industry standards accordingly. The SDT even supports this later claim by directly referencing these standards in the text of this proposed NERC standard (see Requirement R11.4). (5) We believe numerous requirements of this Standards fall under Paragraph 81 Criteria B, and are thus unnecessary. We previously alerted the SDT to this observation and reference portions of its response, listed in its Consideration of Comments posted May 9, here. We concur with the SDT that “Disturbance Monitoring recording is necessary to ensure the reliability of the BES by providing the data for a post event analysis that can determine if system improvements are necessary to ensure reliability [and] guide real-time operating decisions.” However, we disagree that these “supportive requirements are necessary” and feel that the SDT should take some initiative. For reference, we re-list our observations below. (6) We feel Requirement R11 is arbitrary and could be subject to interpretation from auditors due to Paragraph 81 criteria. TOs and GOs could be required to prove the negative, and demonstrate that they have not received a request to provide device data to their RCs, Regional Entities, and NERC. Furthermore, this requirement meets several Paragraph 81 criteria including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. This requirement is administrative because it compels data formats that are immaterial to reliability with the sole purpose to simplify data collection and communication. It meets the data collection/data retention criterion because the requirement is about collecting data. It also meets the reporting criterion because it compels data reporting. We recommend the SDT should remove this requirement in its entirety. It would be more appropriate to include these specifications in a guideline. Furthermore, we feel portions of requirements R1 and R5 are “Periodic Updates” due to the need to reassess each list of affected BES Elements every five calendar years. Likewise, we feel requirements R1, R5, and R11 are “Administrative” due to the need to collect, organize, format, and then circulate data and communications sent to identified entities within a specific timeframe. We feel that several other requirements could be “Data Collection” in nature. Requirements R4.1, R4.2 require the collection of data according to specifications outlined for the minimum recording rate and data duration. Requirements R8.1 and R8.2 require the collection of data according to specifications outlined for the trigger record lengths and trigger settings. Likewise, Requirements R9.1 and R9.2 require the collection of data according to specifications outlined for input sampling rate and output recording rate. Requirement R10 requires the collection of data according to specifications outlined for time synchronization. Finally, we feel Requirement R12 is “Administrative” and “Documentation” in nature based on the need to circulate the discovery of device failure within a specific timeframe and provide a Corrective Action Plan to the Regional Entity if repair is outside this timeframe. (7) Thank you for the opportunity to comment.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst has the following comments for consideration: 1. Requirement R6, Part 6.1.3.2 - For Requirement R6, Part 6.1.3.2 if plant that has six 200 MVA units, does this plant require any DDRs? As currently written, ReliabilityFirst believes no DDRs are required at this facility. From a monitoring perspective, ReliabilityFirst believes any plant/facility that has an aggregate nameplate greater than 1000 MVA, should have equipment capable of DDR. 2. Requirement R12, Part 6.1.3.2 - ReliabilityFirst does not understand the reasoning behind requiring the submission of the timeline for restoration and a Corrective Action Plan (CAP) to the Regional Entity. Without a requirement for the applicable entity to “implement” the CAP, the Regional Entities will have little recourse and there is little value in having the CAP if there is no requirement to complete it. Theoretically, the CAP could go on in perpetuity without completion and the entity would still be compliant, but the problem would remain unresolved. Furthermore, if the requirement requiring the applicable entity to “implement” the CAP, the Regional Entities can monitor implementation through a Regional Entity monitoring method. ReliabilityFirst recommends removing the “for submission to the Regional Entity” language and include implementation language as follows: i. “…restore the recording capability or develop a timeline with milestones for completion for restoration and implement a Corrective Action Plan (CAP).” 3. VSL for Requirement R2 - ReliabilityFirst believes the gradation of

VSLs should be in 10% increments (or similar to the VSL designations for Requirement R1). As written, if an entity only had 51% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers they would only fall under the moderate VSL. ReliabilityFirst believes missing close to half of the total SER data is completely missing the intent of the requirement and should be designated as a “Severe” VSL. ReliabilityFirst has a similar comment for the VSLs associated with requirements R3, R4, R6, R7, R8 and R9.
Individual
Bob Thomas
Illinois Municipal Electric Agency
Individual
Jonathan Meyer
Idaho Power Co.
Yes
Yes
When a relay is used to capture FR data rather than a digital fault recorder, Requirement R4.1 would necessitate a relay record length of at least 32 cycles under R4.1-bullet 1 or multiple triggers under R4.1-bullet 2. Our wide variety of relay types support records of 15, 30, 60, or 180 cycles. Current practice and preference is to use a record length of 30 cycles, trigger inclusive, which was chosen to balance the amount of information in a single record while still providing the capability in the relay to save multiple records. The 32 cycle requirement would force the use of 60 cycle event records. While many of our relays are capable of this, the practice may lead to missed event records impacting our ability to search for misoperations under PRC-004. Multiple triggering has already caused events to be missed in our system due to the limited capability of some legacy relays. A change to a record length of 30 cycles including the 2 cycles of pre-fault trigger would fit within our current practice which mitigates our capture problems.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP (“ICLP”) agrees that there was no reason to keep two sets of requirements for Transmission Owners, Planning Coordinators, and Reliability Coordinators to identify DME locations, and then notify other equipment owners accordingly. The merger of the two sets of requirements makes sense to us.
No
ICLP holds to its position that the 1500 MW criteria established in CIP Version 5 for Medium-Impact generation plants is also appropriate for the placement of Dynamic Disturbance Recorders. In our view, the survey that was performed by NERC when the cyber asset bright-line criteria was developed resulted in a reasonable balance between cost and reliability benefit. There has been no corresponding justification provided under Project 2007-11 that would indicate that the 1000 MW threshold is more appropriate.
ICLP has been closely following the distribution of the Cost Effectiveness Analysis Process (CEAP) survey and its results. We agree with the general findings that the existing base of Disturbance Recorders are mostly sufficient to meet PRC-002-2’s locating and capability requirements – and that the reliability benefit of adding more equipment is minimal. However, it seems to us that NERC’s and the Regional Entities’ data analysis teams feel that the information provided in the evaluation of recent events is still lacking. This conflicts with the equipment owner’s opinions and should be reconciled. Unfortunately, the only justification seems to be that the 2003 investigation recommended the action and FERC directed it be done. This is not a minor point. The benefits of reliability oversight at the national level may be the most difficult to assess, but are the most important. Every dollar spent on compliance needs to be properly allocated, otherwise it will go to less important initiatives. As such, ICLP urges that another CEAP survey be performed – but this

time by the ERO community. Any perceived value should be quantifiable, so that it may be compared to the costs we all take on.
Group
FirstEnergy
Richard Hoag
Yes
Yes
Individual
Bill Temple
Northeast Utilities
Yes
No
The preparation and accuracy of the redlined version and this unofficial comment form is lacking and promotes confusion. The redlined version does not effectively show many of the numerous redlined changes from the last posting, including nearly all of R5. The comment form description of the changes to the implementation plan does not agree with the standard. From above description of changes: "The schedule for implementation is now to be at least 50% compliant within three (3) years following notification of the list, and 100% compliant within five (5) years following notification of the list. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be 100% compliant within five (5) years following notification of the list." From the actual standard posted for comment: Entities shall be at least 50% compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be fully compliant within four (4) years of the Effective Date. Page 11, Requirement 5 states "Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder recording (DDR) data is required, …" While page 5 (blue explanation box& Mapping document) still states "Rationale for Functional Entities: The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the Elements for which dynamic disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected.
Individual
David Kiguel
n/a
Yes
No
1. R5 is unclear as to whether the responsible entity needs to identify BES buses or BES Elements on which dynamic disturbance recording data would be required. 2. Part 5.1.4: It is not clear whether or not the BES Element associated with an IROL is the monitored element or the contingent element, or both. 3. The standard should not specify a number of BES elements (minimum or otherwise) for which DDR data is required. The number of Elements must be determined as those necessary to capture the necessary data to permit the complete study of key events in the BES and should not be pre-determined in the standard.
Group
Duke Energy

Michael Lowman
Yes
No
(1) Duke Energy cannot envision the reliability benefit of including relatively low ATC as a consideration for the placement of DDR equipment in bullet 5 of R5.1.2. Duke Energy suggests the following revision: “5.1.2 Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines: • Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection, or • Transfer Paths in the Western Interconnection Path Rating Catalog, or • Voltage stability limited transfer paths or load serving area, or • Interfaces between Balancing Authority Areas, or • Areas of significant congestion or thermal violation history” If an entity is calculating ATC reliably, there should not be an area of significant congestion or thermal violation history due to the inherent margins (TRM, CBM, etc.) that are built into the ATC calculation. In addition, the ATC consideration is redundant to the previous items in the same bullet.
Group
DTE Electric
Kathleen Black
Yes
Yes
Individual
Brenda Hampton
Luminant Energy Company LLC
Individual
Catherine Wesley
PJM Interconnection
No
PJM signed on the SRC’s response to this question.
No
PJM signed onto the SRC’s response to this question.
PJM urges the drafting team to reconsider including some type of alternative method for determination of the BES buses requiring sequence of events recording and fault recording as stated in the BES detailed methodology included in R1 and detailed in Attachment 1 of the standard. PJM suggested an alternative method that would be less burdensome for entities working on installation of or already have installed modern equipment with FR and SOER capabilities on their circuits. PJM appreciates the drafting team’s consideration of our proposed alternative method and understands that it is not included in the draft standard presently posted. PJM feels strongly regarding inclusion of some type of alternative method and therefore will be submitting a negative ballot for the draft standard.
Individual
Venona Greaff
Occidental Chemical Corporation
Individual
Thomas Standifur
Austin Energy
Yes

City of Austin dba Austin Energy (AE) agrees with the idea of streamlining requirements; however, as noted below in the general comments section (question 3), AE does not agree with this standard as a whole.
No
City of Austin dba Austin Energy (AE), as noted below in the general comments section, does not agree with this standard as a whole. However, AE would like to point out a few clean-up items to Requirement R5. (1) R5 includes the phrase “notify other owners of BES Elements connected to those BES buses”. “[T]hose BES buses” implies reference back to BES buses cited previously in the requirement, but they do not exist. R5 requires the Responsible Entity to identify BES Elements not BES buses. The simple fix is to strike “connected to those BES buses.” (2) AE believes R5 Part 5.2.2 would read better if the SDT changed the phrase "for each additional 3,000 MW” to “for every 3,000 MW.” Otherwise, the Responsible Entity is left asking “in addition to what?”
City of Austin dba Austin Energy (AE) does not agree with this standard as a whole. AE believes it is too prescriptive and unnecessary in the ERCOT region. Regional requirements for ERCOT regarding disturbance monitoring equipment exist in the ERCOT Nodal Operating Guides, Section 6.1. (http://www.ercot.com/mktrules/guides/noperating/cur). Existing requirements provide sufficient data for disturbance monitoring.
Individual
Jose H Escamilla
CPS Energy
Yes
No
Main issue is that “Areas of significant congestion, thermal violation history, or relatively low ATC” is very vague.
Individual
Venona Greaff
Occidental Chemical Corporation
Group
Bureau of Reclamation
Erika Doot
No
The Bureau of Reclamation suggests that the phrase “may require” in R1 and R5 should be changed to “require.” Once an element is identified as requiring data in R1 or R5, R2–R4 and R6–R10 require data collection without exception, so the phrase “may require” could create confusion.
Yes
Individual
Dianne Gordon
Puget Sound Energy
Yes
Yes
Could we use one BES location for both DDR equipment and FR/SER equipment?
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing

Wayne Johnson
Yes
Yes
a. Requirement R11, subsections 11.3, 11.4, and 11.5 do NOT have any impact on the reliability of the system. They are, in fact, entirely administrative in nature. The Results Based Standard template does not support including a requirement of these types. Efforts have been made to remove administrative-type requirements from standards. In this case, a simple mistake in formatting or when naming a file would result in non-compliance with the requirements. b. The GO requirement responsibility should be limited to making available signal sources to the adjoining TO's for the specified list of signals of interest at generating stations. In most cases the TO already owns DM equipment while the GO does not. c. We remained concerned about the cost of the needed equipment where it does already exist; but, we thank the SDT for stretching out the implementation plan which will allow the cost to be allocated over a longer period of time.
Group
Bonneville Power Administration
Andrea Jessup
No
BPA does not believe this Standard should require the Transmission Owner (TO) to notify other owners of BES equipment of their compliance responsibility. BPA also believes that other TOs (in order to determine their own compliance responsibility) should use the same fault MVA data to determine busses to which they have elements connected. BPA feels this requirement, as written, places an undue compliance risk on TOs.
No
BPA feels checks and balances need to be included to ensure Responsible Entities get concurrence from affected TOs/GOs that dynamic disturbance recording (DDR) data is needed at a given location. Additionally, an IROL is defined as in the Long-Term Planning Horizon, not in the operating horizon. BPA also believes R 5.1.5 needs clarification regarding the criteria for “major voltage sensitive area,” — which is related to UVLS (for example, as represented by a metro area of 10 million people / 3000 MW). Otherwise, an isolated radial issue that doesn't impact the Interconnection may be erroneously specified.
BPA does not believe the Cost Effective Analysis Process (CEAP) uses an appropriate comparison example, without clarifying between the 2003 Interconnection wide-area, numerous-state blackout and the 2011 local-area, three-state blackout within an Interconnection, as the 2011 event would naturally take less time and data. BPA does agree, however, with the synchrophasor (PMU) data-speed impact.
Individual
Heather Rosentrater
Avista Utilities
No
Requirement R5 has the Responsible Entity (WECC RC) determining the location of Dynamic Disturbance Recorders (DDR) based on the Western Interconnection Path Rating Catalog or interfaces between Balancing Authorities (BA). WECC has never provided reasoning or justification behind the paths and the selection of the facilities included in the paths. Also the BA does not own or operate any facilities. The more appropriate entity would be the Transmission Operator to determine the interfaces in the BES.
No
Requirement R5 has the Responsible Entity (WECC RC) determining the location of Dynamic Disturbance Recorders (DDR) based on the Western Interconnection Path Rating Catalog or interfaces between Balancing Authorities (BA). WECC has never provided reasoning or justification behind the paths and the selection of the facilities included in the paths. Also the BA does not own or operate any facilities. The more appropriate entity would be the Transmission Operator to determine the interfaces in the BES.

Individual
Glenn Pressler
CPS Energy
No
Main issue is that “Areas of significant congestion, thermal violation history, or relatively low ATC” is very vague.
First issue is that we find the methodology for determining which BES busses may require SER or FR data to be overly complicated and difficult to follow. If the methodology is going to be this complicated, then perhaps the Planning Coordinator or Reliability Coordinator is best suited to perform this analysis so that Transmission Owners do not fall out of compliance for failing to understand an overly complicated spreadsheet with more than 17 steps to determine which busses require this equipment. The second issue is with the requirement of time synchronizing SER data to within +/- 2 milliseconds. While the intent of the standard appears to be to allow many modern existing relays that sample waveforms at 16 samples/cycle, have SER capabilities, and can synchronize to a GPS clock within less than 1 millisecond, this requirement will actually prohibit many of the relays because of the SER requirement. For example, a widely used SEL-311C relay can have its clocked synced to within 1 microsecond, the SER is only time-stamped once every quarter cycle, which is the processing interval of the processor. This means that the SER can only be accurate to within +/- 5 milliseconds. We think this may not be realized by the drafting team and/or many stakeholders. Additionally, we believe that the +/- 5 millisecond accuracy should be more than accurate enough if only a breaker status is required by SER. Two things to note: 1) the breaker 52a or 52b contact that would be input into the DFR device is a mechanical moving device that in and of itself may not be that accurate in regards to an actual indication as to whether the breaker is open or closed. These contacts can often be adjusted as to when they make and occasionally are even wrong in regards to status. 2) Each breaker requiring SER is in many cases already being monitored for currents that give a change of status as to the breaker being open or closed.
Individual
Daniel Duff
Liberty Electric Power, LLC
Generator owners should not be required to install DME. Generators do not model the BES, have no overall awareness of the state of the BES, and are not monitoring the overall state of the BES. The requirement should be, at most, to provide a signal showing breaker position to the TO. Requirements for GOs to provide equipment are properly the realm of the interconnection agreement, not a NERC standard, and the SDT is intruding on the contractual relationship between REs.
Individual
Laurie Williams
PNM
Yes
Yes
Suggested rewording of R12 to clearly state submission of CAP is required. “...develop a timeline for restoration and submit a Corrective Action Plan (CAP) to Regional Entity.”
Individual
D Mason
HHWP

Attachment 1, Step 7 states: "If the list has 11 or fewer BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9." It seems that word "buses" in this sentence should be changed to "bus".

Consideration of Comments

Project 2007-11 Disturbance Monitoring

The Disturbance Monitoring Drafting Team thanks all commenters who submitted comments on the Standard Authorization Request (SAR). These standards were posted for a 45-day public comment period from May 9, 2014 through June 23, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 67 sets of comments, including comments from approximately 173 different people from approximately 111 companies representing all 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

Overall Summary Consideration:

While most stakeholders agreed with the merging of the notification requirement of Requirement R2 into Requirement R1, many have voiced their concerns for various technical hurdles in adhering to the specific methodology prescribed in Attachment 1. However, it is crucial to remember the primary intent of the requirements is that the standard is designed to address "what" data is needed, not "how" it is captured. Further, industry experts continue to emphasize that "why" an event occurred is equally, if not more, valuable than "what" happened. In this sense, as long as the quantities (data) can be determined, the intent of the requirements are satisfied.

Many stakeholders were unhappy with the bulleted list in Requirement R5, Part 5.1.2, either with a single bullet or with the list altogether. The standard drafting team revised Requirement R5, Part, 5.1.2 and removed the bulleted list of "or" statements, replacing it with "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."

In Requirement R5, the use of "BES buses" was found to be confusing by many stakeholders. The use of this language was simply to provide clarity but, in response to industry's comments, the drafting team revised R5 by removing "BES buses". The Requirement now references only BES Elements.

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

A number of stakeholders voiced their concerns for more precise wording of the Step 7 in Attachment 1 which stated "If the list has 11 or fewer BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA." The ambiguity arose out of the term "buses" because it could be read as requiring FR and SER data from more than one bus. Thus, Step 7 is now revised to read "If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA."

Several stakeholders also commented that Requirement R11 had no substantial impact on improving the reliability of the system. The DMSDT notes that the Requirement R11 ensures data availability from the data sources, timely retrievability of the data and common format so that the data can be read and used in the expeditious and effective analysis of events. Requirement R11 provides a reliability impact by integrating all of the previous requirements in the standard with respect to data reporting facilitate event analysis. The first two Parts of Requirement R11 specify how long an entity has to provide requested data (Part 11.1) and also limits how long data must be retained by the TO or GO (Part 11.2). Parts 11.3-11.5 ensure the uniformity and consistency of the data that is reported.

One technical change many stakeholders proposed was to revise Requirement R10 to relate to time synchronization of the device clock rather than data. The Requirement's original language called for time synchronization of SER data within +/- 2 milliseconds. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices are within ± 2 ms accuracy will suffice with respect to providing time synchronized data. The drafting team revised Requirement R10 accordingly.

Based on stakeholder feedback, the DMSDT capitalized the defined terms System, Transmission and Disturbance. The DMSDT believes that this adds clarity regarding the requirements and rationales in PRC-002-2. In some instances, these terms appear adjacent to each other within sentences of Requirements, Rationales or Guidelines. The following instances occur:

- Transmission System
- System Disturbance
- System Demand

The DMSDT has also incorporated the defined term "Transmission Line". The DMSDT does not intend to create any new defined terms by the above uses. Each defined term stands on its own.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	NERC Compliance Policy	SERC	1, 3, 5, 6
2.	Louis Slade	NERC Compliance Policy	RFC	1, 3, 5, 6
3.	Randi Heise	NERC Compliance Policy	MRO	1, 3, 5, 6
4.	Chip Humphrey	Power Generation Compliance	RFC	5
5.	Jeff Bailey	Nuclear Compliance	NPCC	5
6.	Larry Nash	Electric Transmission Compliance	SERC	1, 3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10

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

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Jared Shakespeare	Peak Reliability	X									

N/A

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X		X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6

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

7.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

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

N/A

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

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

				1	2	3	4	5	6	7	8	9	10
7.	Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5

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

5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			RFC	6
10.			SPP	6
11.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Clancy	Cleco Power	SPP	1, 3, 5, 6
2.	Louis Guidry	Cleco Power	SPP	1, 3, 5, 6
3.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6
4.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
5.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
6.	Mike Kidwell	Empire Electric District	SPP	1, 3, 5
7.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
8.	Shannon Mickens	Southwest Power Pool	SPP	2
9.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
10.	Frankie Smith	Kansas City Power & Light	SPP	1, 3, 5, 6
11.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

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

N/A

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		
2.	Greg Davis	Georgia Transmission Corporation		
3.	Bridget Coffman	Santee Cooper		
4.	Charlie Fink	Entergy		
5.	David Greene	SERC		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
12.	Group	Thomas McElhinney	JEA	X		X		X					

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Greg Campoli	ISO RTO Council Standards Review Commitee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Cheryl Moseley	ERCOT	ERCOT	2
2.	Charles Yeung	SPP	SPP	2
3.	Ali Miremadi	CAISO	WECC	2
4.	Lori Spence	MISO	MRO	2
5.	Matt Goldberg	ISONE	NPCC	2
6.	Ben Li	IESO	NPCC	2
7.	Stephanie Monzon	PJM	RFC	2

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

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

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

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

8. Stanley Rzad	Keys Energy Services	FRCC	1
9. Mark Schultz	City of Green Cove Springs	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Brian Van Gheem	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
2. Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3. Allan George	Sunflower Electric Power Corporation	SPP	1
4. Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
5. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
6. John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
7. Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Richard Hoag	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. William Smith	FirstEnergy Corp	RFC	1
2. Cindy Stewart	FirstEnergy Corp	RFC	3
3. Doug Hohlbaugh	Ohio Edison	RFC	4
4. Ken Dresner	FirstEnergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6
6. Richard Hoag	FirstEnergy Corp	RFC	NA

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

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19. Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Regulated Marketing	RFC	5
4. David Szulczewski	SEE	RFC	

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Karie Barczak		NERC Compliance	RFC										
20.	Group	Erika Doot	Bureau of Reclamation	X				X					
Additional Member		Additional Organization	Region / Segment Selection										
1. Richard T Jackson													
2. Shawn Patterson													
21.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
N/A													
22.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				
Additional Member		Additional Organization	Region / Segment Selection										
1. Jim Burns		Technical Operations	WECC 1										
23.	Individual	David Jendras	Ameren	X		X		X	X				
24.	Individual	Leonard Kula	Independent Electricity System Operator		X								
25.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
26.	Individual	Tracy Richardson	Springfield Utility Board			X							
27.	Individual	John Allen	City Utilities of Springfield, MO	X		X	X						
28.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
29.	Individual	Barbara Kedrowski	Wisconsin Electric Power Co			X	X	X					
30.	Individual	David Thorne	Pepco Holdings Inc.	X		X							
31.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
32.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
33.	Individual	Scott Langston	City of Tallahassee	X									
34.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
35.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
36.	Individual	Karen Webb	City of Tallahassee					X					
37.	Individual	Alshare Hughes	Luminant Generation Company, LLC	X		X		X					
38.	Individual	Dan Roethemeyer	Dynegy					X					
39.	Individual	Michael Moltane	ITC	X									
40.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
41.	Individual	John Brockhan	CenterPoint Energy Houston Electric, LLC	X									
42.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
43.	Individual	Chris Scanlon	Exelon Companies	X		X		X	X				
44.	Individual	Oliver Burke	Entergy Services, Inc.	X									
45.	Individual	Bill Fowler	City of Tallahassee			X							
46.	Individual	Don Schmit	Nebraska Pubilic Power District	X		X		X					
47.	Individual	John Pearson	ISO New England		X								
48.	Individual	Karin Schweitzer	Texas Reliability Entity										X
49.	Individual	Gul Khan	Oncor Electric Delivery LLC	X									
50.	Individual	Anthony Jablonski	ReliabilityFirst										X
51.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
52.	Individual	Jonathan Meyer	Idaho Power Co.	X									
53.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
54.	Individual	Bill Temple	Northeast Utilities	X									
55.	Individual	David Kiguel	n/a								X		
56.	Individual	Brenda Hampton	Luminant Energy Company LLC						X				
57.	Individual	Catherine Wesley	PJM Interconnection		X								
58.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
59.	Individual	Thomas Standifur	Austin Energy	X		X		X	X				
60.	Individual	Jose H Escamilla	CPS Energy	X		X		X					
61.	Individual	Venona Greaff	Occidental Chemical Corporation							X			

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
62.	Individual	Dianne Gordon	Puget Sound Energy	X		X		X					
63.	Individual	Heather Rosentrater	Avista Utilities	X		X		X					
64.	Individual	Glenn Pressler	CPS Energy	X		X		X					
65.	Individual	Daniel Duff	Liberty Electric Power, LLC					X					
66.	Individual	Laurie Williams	PNM	X		X							
67.	Individual	D Mason	HHWP					X					

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

Summary Consideration:

Organization	Agree	Supporting Comments of "Entity Name"
Santee Cooper	Agree	We agree with the comments submitted by SERC PCS.
ISO New England	Agree	ISO RTO Council Standards Review Committee (SRC)
Illinois Municipal Electric Agency	Agree	Florida Municipal Power Agency, and PJM
Luminant Energy Company LLC	Agree	Luminant Generating Company LLC
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP

1. **The DMSDT merged the notification requirement of Requirement R2 into Requirement R1. The DMSDT also merged the notification requirement of Requirement R7 into Requirement R6 (new R5). Do you support these new requirements? If not, please explain why and provide suggested changes.**

Summary Consideration: While most stakeholders agreed with the merging of the notification requirement of Requirement R2 into Requirement R1, many have voiced their concerns for various technical hurdles in adhering to the specific methodology prescribed in Attachment 1. However, it is crucial to remember that the primary intent of the standard's requirements is that they are designed to capture "what" data is recorded, not "how" it is recorded. Further, industry experts continue to emphasize that "why" an event occurred is equally, if not more valuable than "what" happened. In this sense, as long as the quantities (data) can be recorded or determined, the intent of the requirements are satisfied.

Organization	Yes or No	Question 1 Comment
Peak Reliability	No	The initial list of locations should come from the owners (TOs and GOs) with a subsequent review process as identified by the Responsible Entity. The Responsible Entity should have the authority to require additions as it sees necessary. Owners should provide the initial list because they have access to the information and would bear the cost of installing DDRs.
Response: FR and SER locations are determined by the Transmission Owners. The DMSDT has assigned the responsibility for DDR data locations to the Responsible Entity (Peak Reliability in WECC) because DDR data is reflective of a wide area System response and it is appropriate for the Responsible Entity to identify what BES Elements data is needed for. It is the responsibility of the RC in WECC to develop the list, but development of the DDR list can be done collaboratively through WECC committees. An initial list has already been prepared by WECC JSIS, whose members are primarily operating entities. The Responsible Entity can add or remove locations from this list per Requirement R5 for DDR data. The DMSDT considered FR and SER data as primarily localized information, with the TO being better suited to make the selections.		
ISO RTO Council Standards Review Committee	No	We agree with the merging of R2 into R1, but not the revised R5 which combined R6 and R7. Please see our comments under Q2, below.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. Please see the DMSDT response to your comments to Question 2.		
Seattle City Light	No	R1 does not meet NERC principles for world-class Standards, because it includes three separately audited control activities in a single sentence: (1) identify buses, (2) notify others of buses, (3) reassess every five years. If this draft Standard is deemed necessary, Seattle recommends rewriting R1 to include three subrequirements as follows: R1. Each Transmission Owner shall: R1.1 Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1. R1.2 Notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days that those BES Elements may require SER data and/or FR data. R1.3 Reevaluate the identified BES buses at least once every five calendar years. In addition, the draft Standard does not clarify required actions should the five-year reassessment identify a different selection of buses for which monitoring now would be required. Seattle suggests that an implementation period be identified for installing SER and FR equipment for newly identified buses similar to the implementation time for the initial implementation of the Standard. Likewise, the Standard does not clarify how newly constructed buses are handled. Seattle suggests that that they be evaluated at the next 5-year reassessment, rather than individually as they are brought on line.
Response: The Drafting Team has revised Requirement R1 as per your comments. **The Implementation Plan addresses data recording capability for newly-identified buses and BES Elements--"Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." This language was added to Part 1.3 of the revised Requirement R1 in the standard for clarity. The Rationale Boxes for Requirements R1 and R5 explain the reevaluation interval: newly identified BES buses and BES Elements are identified at the five-year reassessment. The implementation of the reassessed list will be as per the Implementation Plan.**		

Organization	Yes or No	Question 1 Comment
As the standard is written, newly constructed BES buses or Elements are handled via the reevaluation of the identified BES buses, not individually as they are brought online.		
Florida Municipal Power Agency	No	see question 3
Response: Thank you for your comment. Please see the DMSDT responses to your comments under Question 3.		
ACES Standards Collaborators	No	We concur with the SDT's observation and rationale that "the requirement for DDR data for identified BES Elements...is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis." We feel that industry is not only capable of identifying the number of devices from this experience, but also where these devices should be located for dynamic disturbance recording, sequence of events recording, and fault recording purposes. We believe this standard should require an entity to generate its own methodology to make these determinations and how often. We feel the method proposed for selecting BES Elements is too broad and could be subject to interpretation from auditors when not properly followed. We also have concerns that the SDT has not identified a transition period in the standard when a Reliability Entity identifies or receives notification that they are then required to install a recording device. The only transition period the SDT has accounted for is what the SDT listed in the implementation plan and based on the effective date of the standard.
Response: The Standard Drafting Team, after extensive outreach to industry experts related to event analysis and Disturbance Monitoring, identified BES Elements that, if covered by disturbance recording, would significantly contribute to effective, efficient and accurate analysis. Industry experts continue to highlight that "why" an event occurred is equally valuable, if not more valuable, than "what" happened. Even with the proliferation of DDR, defining critical BES Elements requiring monitoring ensures adequate data is available for event analysis purposes. The DMSDT has outlined these BES Elements in Requirement R5, selecting		

Organization	Yes or No	Question 1 Comment
the minimum set of Elements necessary for this analysis. Allowing entities to develop their own methodology could lead to inconsistency and uncertainty in capturing the data necessary for event analysis purposes. **It must be emphasized that an entity will not be notified that it has to install recording devices. An entity will only be notified that it has to have the data for what it has been notified for. The Responsible Entity develops a list of BES Elements for which DDR data is required. That list is provided to the TOs and GOs of their respectively owned Elements. The TOs and GOs are then required to provide that DDR monitoring capability, as per the Implementation Plan. The Implementation Plan regarding the TOs and GOs required to provide DDR monitoring capability, states:** **"Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:** **• Entities shall be at least 50 percent compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date.** **• Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the Effective Date.** **Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list."** **This addresses the transition period for the TOs and GOs to implement necessary monitoring for both the initial list developed and subsequent reassessments. The DMSDT also revised Requirement R1 to clarify the implementation of the reevaluated list.** **"1.3. Reevaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan."**		
Bureau of Reclamation	No	The Bureau of Reclamation suggests that the phrase "may require" in R1 and R5 should be changed to "require." Once an element is identified as requiring data in R1 or R5, R2-R4 and R6-R10 require data collection without exception, so the phrase "may require" could create confusion.
Response: The wording in Requirements R1 and R5 was revised, and "may" was removed from the requirement.		
Bonneville Power Administration	No	BPA does not believe this Standard should require the Transmission Owner (TO) to notify other owners of BES equipment of their compliance

Organization	Yes or No	Question 1 Comment
		responsibility. BPA also believes that other TOs (in order to determine their own compliance responsibility) should use the same fault MVA data to determine busses to which they have elements connected. BPA feels this requirement, as written, places an undue compliance risk on TOs.
Response: There are BES buses connected to BES Elements owned by different entities. The studies done by the different owners to identify monitored BES buses could yield different results for what needs to be monitored; which necessitates the notification from one Transmission Owner to another.		
Independent Electricity System Operator	No	We agree with the merging of R2 into R1, but not the revised R5 which combined R6 and R7. Please see our comments under Q2, below.
Response: Thank you the comment. Refer to the DMSDT response to your comment in Question 2.		
City Utilities of Springfield, MO	No	We support the merging of R2 into R1 and R7 into new R5. However, we do not support R1 Attachment 1 methodology regarding identifying BES buses for locating SER & FR devices to capture SER & FR data. See comments in question #3 for our reasoning.
Response: Thank you for your comment. Refer to the DMSDT response to your comment to Question 3.		
American Electric Power	No	R1: The scope for the process in Attachment 1 should be limited to only those BES buses that have local protection systems that serve to protect the connected BES elements. R1: The process for identifying BES buses within Attachment 1 could lead to a breaker protected load bus, with only two BES source lines, being in the "top 10%" of locations that must have DFR/SER. The reason for such a location being in the top 10% would be driven by its proximity to other top 10% BES buses. The Standard should allow for exclusion of such locations, provided they are substituted by the next BES bus in the list. AEP believes this change would allow DFR/SER equipment to be deployed where proper

Organization	Yes or No	Question 1 Comment
		event analysis is truly needed. An alternate approach would be to completely eliminate the top 10% criteria, which would allow industry maximum flexibility in determining the most appropriate location for such installations. R1 & R5: As written, these requirements are single sentences which are five lines in length. With no transitions of thought, they are difficult to read. The wording should be revised to break up independent thoughts so it reads more concisely. R1 & R5: The notification within 90 calendar days has no reference point. The requirements should be revised to state "... within 90 days of completing the Attachment 1 methodology" or similar wording. R1 & R5: Both requirements state "BES Elements may require..." Why is this a "may" statement? This seems to be in conflict with the beginning statement of the requirement that indicates a bright line identification of what requires monitoring. AEP recommends employing a consistent structure for R1 and R5. The criteria for R1 are contained within an appendix, while the criteria for R5 are contained within the requirement. AEP recommends modifying R1 so that the notified entity has the option to monitor either the local or the remote terminal of the subject Element.

Response:

The DMSDT notes that Requirement R1 specifies BES buses/Elements where FR and SER data (not equipment) is required to be captured. The data itself is specified in Requirement R3 which states "Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each of the BES Elements it owns connected to the BES buses identified

Organization	Yes or No	Question 1 Comment
in Requirement R1:" As long as the quantities (data) can be determined, the intent of the requirements are met. This standard identifies minimum data requirements. The DMSDT has revised Requirements R1 and R5 for clarity. The DMSDT agrees and has revised the wording to include "… within 90 calendar days of completion of Part 1.1…" and "…within 90 calendar days of completion of Part 5.1…" The DMSDT agrees and has revised the wording to remove "may" from both requirements. The DMSDT notes that Attachment 1 contains a procedure, while Requirement R5 contains bright line criteria for DDR data. It does not matter at which terminal data is captured, as long as the required data can be determined.		
City of Tallahassee	No	see response for question 3
Response: Thank you. Refer to the DMSDT response to your comment to Question 3.		
Kansas City Power & Light	No	See comments at end of form.
Response: Thank you. Refer to the DMSDT response to your comment to Question 3.		
City of Tallahassee	No	Please see comment for question 3.
Response: Thank you. Refer to the DMSDT response to your comment to Question 3.		
Exelon Companies	No	Exelon does not agree with the SOE/FR requirements as written but not because of the merging of the R2 and R1 requirements. We believe that there needs to be a streamlined process for entities that are modernizing their system. The SOE and FR portions of this standard are very close to 100% burden to entities that are utilizing modern microprocessor relays connected to GPS clocks for T-lines on their system as a standard. The

Organization	Yes or No	Question 1 Comment
		proposal does not account sufficiently for technical changes that have occurred over the last ten years. The Attachment 1 process is overly burdensome for entities modernizing their systems. An alternative to the attachment 1 process is for an entity to identify that 40% of its BES transmission lines (transformers need not be monitored if lines are monitored) include FR and SER capability. This would be easy to demonstrate as these types of lists are readily available already. Additionally, we believe the reference to BES Elements / Busses needs clarification. We also object to the TO having the responsibility to notify others of their need to comply with a NERC standard, "notify other owners of BES Elements connected to those BES buses".
Response: The standard deals with "what" data is recorded, not "how" it is recorded. Analysis of industry data submitted in response to the June 5, 2013 Request for Data verified that a straight percentage of BES Elements would not be the best way to establish what's needed to have data recorded. Also, please note that Requirement R3 states, "Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each of the BES Elements it owns connected to the BES buses identified in Requirement R1:" As long as the quantities (data) can be determined, the intent of the requirements are met. The DMSDT does not consider this methodology to be burdensome, and is practical to determine the data that is required. There are BES buses connected to BES Elements owned by different entities. The studies done by the different owners to identify monitored BES buses could yield different results for what needs to be monitored; which necessitates the notification from one Transmission Owner to another.		
City of Tallahassee	No	see comment for question 3
Response: Thank you. Refer to the DMSDT response to your comment to Question 3.		
Nebraska Public Power District	No	R1 should have some explanation for what the implementation/installation deadlines are for newly identified BES buses as part of the 5 year review. R1

Organization	Yes or No	Question 1 Comment
		states “reevaluate the identified BES buses at least once every five calendar years”, should this read “reevaluate all BES buses at least once every five calendar years”? It seems that new buses may be added and existing buses in the required locations for FR may get dropped down the list and become discretionary. R2 rational states “time stamped according to Requirement R10 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance.” Since relays and FR recorders often use separate clocks consider changing “common clock” to “time synchronized clock”. R7 states: “Each Generator Owner shall have DDR data for each BES Element it owns and is notified according to Requirement R5”. Should this read “Each Generator Owner shall have DDR data for each BES Element it owns as notified according to Requirement R5” instead? It seems a bit confusing how to read this requirement. It could be read that the GO “shall have DDR data for each BES Element it owns”. Consider if this requirement can be clarified or restated.

Response: The DMSDT agrees and has revised Requirement R1 to: “1.3 Reevaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.” The Implementation Plan specifies that "Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." The intent is to reevaluate all BES buses every five years.

R2: The SDT agrees and has revised the wording in the Rationale Box.

R7: The SDT agrees with you and has revised Requirement R7 to mirror the wording found in Requirement R6:

> **“R7. Each Generator Owner shall have DDR data for each BES Element it owns, for which it received notification as identified in Requirement R5, to determine the following electrical quantities:”**

Organization	Yes or No	Question 1 Comment
PJM Interconnection	No	PJM signed on the SRC's response to this question.
Response: Thank you for the comment. Please see the DMSDT responses to those comments.		
Avista Utilities	No	Requirement R5 has the Responsible Entity (WECC RC) determining the location of Dynamic Disturbance Recorders (DDR) based on the Western Interconnection Path Rating Catalog or interfaces between Balancing Authorities (BA). WECC has never provided reasoning or justification behind the paths and the selection of the facilities included in the paths. Also the BA does not own or operate any facilities. The more appropriate entity would be the Transmission Operator to determine the interfaces in the BES.
Response: The bulleted components of Part 5.1.2 have been removed and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)." The Responsible Entity has the overall view of the BES and is the appropriate entity to determine what data would need to be captured.		
Dominion	Yes	
Northeast Power Coordinating Council	Yes	The term BES bus is not a defined term, it is only described in Step 1 of Attachment 1. Note that NERC's Definition of Bulk Electric System (Phase 2) definition applies to Elements. Requirement R3, sub-Part 3.1 requires to have "Phase-to-neutral voltages for each phase of each specified BES bus". Since BES buses, as described in Attachment 1, may not represent physical buses, this sub-Part is not clear. For example, a breaker-and-a-half design with two physical buses. A Transmission Owner (TO) might not have visibility of the BES classification of Elements it does not own. It is recommended that the TO provide the list of identified BES buses to their PC / RC. The PC/RC will review the received list from the TO, and determine if the list contains BES Elements

Organization	Yes or No	Question 1 Comment
		owned by others, and notify those owners whose BES Elements may require sequence of events recording (SER) and/or fault recording (FR) data. Reference to (undefined) BES buses in Requirement R5 makes this requirement open to interpretations. Sub-Part 5.1.2 requires the inclusion of “Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity”, and its bullets include stability related interfaces or other significant Flowgates, Elements associated with Interconnection Reliability Operating Limits (IROLs), and voltage stability limited transfer paths or load serving areas. The different Parts and sub-Parts of R5 could require a large number of DDRs for TOs which have Flowgates, IROLs, and /or UVLS schemes. The number of required DDRs could become significantly larger than the minimum set of one BES Element plus one additional BES Element for each additional 3,000 MW of load, which could cause excessive burden on some TOs. It is also suggested to eliminate the potential overlap of sub-Parts 5.1.2, 5.1.4, and 5.1.5 by consolidating sub-Parts. Finally, it is recommended that "One or more BES Elements associated with Interconnection Reliability Operating Limits (IROLs)" in sub-Part 5.1.4 be replaced with “Any one BES Element critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies” to be consistent with the language in CIP-002-5.1. Sub-Part 5.1.4 requires clarification. The Drafting Team should consider shortening R1 by listing Parts.

Response: Requirement R1 specifies the identification of BES buses. Attachment 1, Step 1 says: "For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing; a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus." Under a normal system

Organization	Yes or No	Question 1 Comment
configuration, the voltages around a station's bus would be the same. Just capturing the data for that "single node" of physical buses is all that is required. **The TO only has to know the classification of Elements it owns and ensure that there is data capturing capability for those Elements.** **The wording of Requirement R5, Part 5.3 was revised to remove BES buses.** **The bulleted components of sub-Part5.1.2 have been removed and replaced with: "Any one BES Element that is part of a stability or voltage related System Operating Limit (SOL).** **The wording of Requirement R5 and its Parts have been revised in response to comments received.** **Requirement R1 has been revised to break out wording into requirement Parts.**		
MRO NERC Standards Review Forum	Yes	
Response:		
Colorado Springs Utilities	Yes	
Response:		
Associated Electric Cooperative, Inc. - JRO00088	Yes	
Response:		
PPL NERC Registered Affiliates	Yes	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or

Organization	Yes or No	Question 1 Comment
		more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
SPP Standards Review Group	Yes	
Arizona Public Service Company	Yes	
SERC Protection and Controls Subcommitee	Yes	
FirstEnergy	Yes	
Duke Energy	Yes	
DTE Electric	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	
Wisconsin Electric Power Co	Yes	
Pepco Holdings Inc.	Yes	

Organization	Yes or No	Question 1 Comment
Seminole Electric Cooperative, Inc.	Yes	
Xcel Energy	Yes	In general, several requirements stacked into one can lead to missed activities/compliance issues, but we defer judgment on this to the NERC Standards Committee review and standards development guidelines.
Response: Thank you for your comment.		
Luminant Generation Company, LLC	Yes	
ITC	Yes	
Tacoma Power	Yes	Tacoma Power disagrees with the need for this standard. However, assuming that this standard will likely proceed to approval, Tacoma Power takes no exception to merging these requirements.
Response: Thank you for the comment.		
CenterPoint Energy Houston Electric, LLC	Yes	
Entergy Services, Inc.	Yes	
Texas Reliability Entity	Yes	
Oncor Electric Delivery LLC	Yes	Oncor supports combining identification and notification into one requirement as done in the latest draft.
Response: Thank you for your comment.		
Idaho Power Co.	Yes	

Organization	Yes or No	Question 1 Comment
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP (“ICLP”) agrees that there was no reason to keep two sets of requirements for Transmission Owners, Planning Coordinators, and Reliability Coordinators to identify DME locations, and then notify other equipment owners accordingly. The merger of the two sets of requirements makes sense to us.
Response: Thank you for your comment.		
Northeast Utilities	Yes	
n/a	Yes	
Austin Energy	Yes	City of Austin dba Austin Energy (AE) agrees with the idea of streamlining requirements; however, as noted below in the general comments section (question 3), AE does not agree with this standard as a whole.
Response: Thank you for your comment.		
CPS Energy	Yes	
Puget Sound Energy	Yes	
PNM	Yes	

2. **The DMSDT revised the requirements for dynamic disturbance recording data based on stakeholder comments. Do you agree with the BES Elements requiring dynamic disturbance recording data listed in Requirement R5? If not, please provide technical justification.**

Summary Consideration:

Many stakeholders were unhappy with the bulleted list in Requirement 5.1.2, either with a single bullet or with the list altogether. The standard drafting team revised R5.1.2 and removed the bulleted list of "or" statements, replacing it with "Any one BES Element that is part of a stability or voltage related System Operating Limit (SOL)"

In Requirement R5, the use of "BES buses" was found to be confusing by many stakeholders. The use of this language was simply to provide clarity but, in response to industry's comments, the drafting team revised R5 by removing "BES buses".

Organization	Yes or No	Question 2 Comment
Peak Reliability	No	The reference to the WECC Path Rating Catalog should be removed because the remaining bullet points cover everything in the Path Rating Catalog. The WECC Path Rating Catalog can be changed without going through any Standard development process. Changes to the Path Rating Catalog changes Requirement impact.
Response: The bulleted list of "or" statements has been removed from the standard and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
Associated Electric Cooperative, Inc. - JRO00088	No	Note that AECI agrees with the current PRC-002-2 R5.1.2 Bullet#1 wording related to Flowgates, and appreciates this SDT's being thoughtfully responsive to prior comments.FOR: PRC-002-2, R5.1.2, Bullet #5REMOVE: "or relatively low Available Transfer Capability (ATC)"RATIONALE: AECI believes calculated ATC is based upon many complex factors that are somewhat subjective, primarily Market related, and

Organization	Yes or No	Question 2 Comment
		therefore a technically weak indicator for locating where reliability-related DDR equipment should be located.
Response: The bulleted list of "or" statements has been removed from the standard and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
PPL NERC Registered Affiliates	No	We agree that DDR data should be obtained for the transmission lines from generation plants as listed in requirement 5.1.2, but not that GOs are the parties that should collect this information. DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data; GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording/storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. DDR data collected on the TO's side of the generation plant battery limits would be the same as that measured on the GO's side, so one could apply the same logic as is stated on p.33 of the standard for FR data, "For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection." Moreover, as regarding assignment of responsibility for monitoring disturbances, such events are more likely to originate in the transmission system (as was the case for the Northeast blackout of 2003) than in generation plants. The SDT emphasized in its discussion of 6/11/14 with the NAGF Standards Review Team that duplication of equipment is not mandated - a GO can contract with its TO to supply the data if the TO has DME at a plant or is willing to add such equipment. We are concerned that the SDT may not have considered the difficulty in negotiating such agreements for the provision of such data or the transfer of compliance responsibilities. A requirement in the standard that TOs must coordinate with generators to provide the data where they own DME at a generation plant would be preferable if GOs have any responsibility under the standard. The least-total-cost approach should be followed in obtaining the expected reliability benefits, and we believe that centralizing DME with TOs makes more sense than splitting the responsibilities between involved entities (TOs) and those who merely hand-over

Organization	Yes or No	Question 2 Comment
		recordings (GOs) for further analysis. We recommend that the SDT perform a cost-benefit analysis of the two approaches before finalizing this standard.
Response: The Purpose of PRC-002-2 is: "To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances." It is important to note that large generating resources are an equal component to the BES and disturbances on the BES as the Transmission system. Tripping of (large) generating Facilities can, and do, pose a risk of underfrequency conditions across an Interconnection. The power grid is a giant, rotating synchronized machine with Transmission lines simply carrying the power generated by power plants. Past experience has shown that using the data from the Transmission grid is insufficient to determine the cause of generator outages. The response of the generating fleet is a strong player in the overall electrical response of the system. As in the 2003 blackout, the 2011 blackout and other blackouts, the sequence of events was able to be recreated using data across the network. Time-synchronized data greatly improved the response and understanding of time aligning the events in the 2011 blackout. However, it is crucial to note that in both cases it is still unclear why the blackout evolved and why generating resources did not respond as expected, or as studied in the power flow and dynamic simulations. For analysis, it is important to understand why the generating plant tripped offline, not when. This information is generally not available because the generating resource owners have insufficient recording capability at the plant to understand how the unit is responding during the transient System conditions. This understanding is required in order for Planners, Event Analysis staff and those responsible for the reliability of the electric grid supposed to create responsive schemes such as Underfrequency Load Shedding Schemes or Remedial Action Schemes to maintain the electrical connectivity of the grid. Generation plays a critical role in the reliability of the electrical grid, and the DMSDT feels that having generator DDR data for large generating resources is a cost effective way to ensure "adequate data to facilitate event analysis of Bulk Electric System (BES) disturbances." The standard is not concerned with "how" data recording is accomplished, but rather with "what" data is recorded. The standard allows for flexibility without being prescriptive in this respect, allowing the GO to determine the most cost-effective and least duplicative means of recording the data that is necessary for overall reliability and event analysis of the BES. The DMSDT believes that the responsibility for the data lies with the owner of the BES Elements requiring DDR data.		
SERC Protection and Controls Subcommittee	No	(1) R 5.1.2. Still seems open ended for us. The following bullet points under this requirement give reasons for concern: o Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection o Interfaces between Balancing Authority Areas o Areas of significant congestion,

Organization	Yes or No	Question 2 Comment
		thermal violation history, or relatively low Available Transfer Capability (ATC)DDR are applied for stability reasons, so thermal violations, and low ATC are not valid justification. (2) Depending on how our Planning Coordinator interprets these points, we could still be put upon to install an indeterminately large number of PMUs. This language *is* a step in the right direction from the previous draft of the standard, where "all permanent Flowgates" required DDR equipment, however, our preference would still be to delete R 5.1.2 from the standard. (3) If 5.1.2 is retained, please add a section 5.3 “The number of BES Elements need not exceed one per 1000 MW of its historical peak system Demand.” This provides sufficient coverage in the Responsible Entity’s area and encourages the RE to be ‘responsible’ in applying the 5.1.2 guidelines. (4) Some software vendors do not presently have the full capability as described in Requirement 11 implemented in their equipment or DME application software. This could require change out of the existing equipment. (5) Please clarify the 3rd paragraph of Rationale for R5 by adding ‘only one’ so its consistent with Guidelines and Technical Basis section page 36:’For “major transmission interfaces” with the exception of HVDC, the DDR data is to be captured for only one BES Element, and, is obtainable from one terminal (either end) of an Element.’ Also add: ‘If the BES Element has multiple owners, each TO and / or GO will need to agree which owner will have the DDR data, and the other owners can refer to this agreement as their means of meeting their obligations.’ (6) Please add ‘If the BES Element has multiple owners, each TO (and / or GO, as appropriate)will need to agree which owner will have the DDR data (or equipment, as appropriate), and the other owners can refer to this agreement as their means of meeting their obligations.’ In the rationales for R6, R7, R8, R9, R10, R11, and R12 to be consistent with R5 and cover tie line Elements. Similarly, M6 through M12, add

Organization	Yes or No	Question 2 Comment
		the option that for BES Elements with multiple owners, the TO / GO can provide an agreement stating which owner is responsible for the DDR data. (7) The standard should include direction if agreement between entities cannot be reached i.e. “In cases where agreement between entities cannot be reached, the TO/GO that necessitates DM capability is ultimately responsible for the equipment and any /all requirements.”

Response:

(1, 2) The bulleted list of "or" statements has been removed from the standard and replaced with: “Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).” The concept of “all permanent flowgates” and “major transmission interfaces” was removed from the standard. The more widely used SOL concept replaces these items to capture those major transmission elements.

(2, 3) The Drafting Team understands the concern with overburdening the TOs with DDR data. However, the Drafting Team does not feel that an upper threshold number for DDR coverage be placed; this could lead to insufficient DDR capability applied to the BES particularly in heavily loaded areas where DDR data would be valuable. It is expected and the intent of this standard that the flexibility provided to the Responsibility Entity can be used to utilize existing DDR capability and provide an adequate wide-area view with respect to DDR data.

(4) The draft standard does not dictate that particular DDR equipment have specified software specifications except for the output reporting rate requirement. After consulting with industry subject matter experts, the majority of existing equipment can meet the specifications put forth for data formatting. However, it is also understood that there are software tools available or can be programmed to simply convert one format of data to another format. For example, Phasor Measurement Unit data often reports in C37.118 format, but can be (and often is) converted to COMTRADE format for data sharing purposes. In addition, SER records are being requested in a .csv format to facilitate a more streamlined approach to event analysis from multiple entities, as this is often the biggest bottleneck of the event analysis process. Event records can be easily saved into a .csv format using MS Excel.

(5) The language in the requirements, Rationale Boxes, and Guidance and Technical Basis Section have been revised for consistency.

Organization	Yes or No	Question 2 Comment
		(6) It is expected that multi-owner BES Elements will be dealt with in the same manner as any other NERC Standard applicability and the DMSDT does not see the need to try to address the permutations that could possibly arise due to multiple ownership scenarios in this standard. **(7) For multiple ownership, there are already agreements that exist that define who is responsible for what.**
ISO RTO Council Standards Review Committee	No	Please clarify in R5 whether the first use of the term “BES Elements” is intended to be used here. It appears the intent is that the responsible entities notify all owners of the BES facilities connected to the BES Buses which they have identified. In that case, that term should be “BES Buses” or both BES Elements and BES Buses. We are concerned that the last bullet in Part 5.1.2 may be interpreted to include congestion as it relates to commercial/economic use of transmission interfaces. The term “significant Flowgates” should be limited to only physical/electrical constraints and not congestion that can be mitigated by market mechanisms. Part 5.1.4 needs to clarify whether BES Elements associated with the Interconnected Reliability Operating Limit should include only the monitored element or the contingent element or both. The Rationale for R5 should include the technical reason why the “Responsible Entity” is the applicable entity for identifying buses/elements for DDR events. As stated in the Background Information of the Comment Form, the SDT states the PC or RC has the overall view of the BES for DDR. This explanation should be included in the standard. R5 is also confusing in what is the requirement for BES Element owners which have been identified as needing DDR. We recommend the following changes to ensure the DDRs are applied on the proper BES Elements:” Each Responsible Entity shall (i) identify BES Elements for which dynamic disturbance recording (DDR) data is required, (ii) notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements WILL require DDR data upon

Organization	Yes or No	Question 2 Comment
		request of the Responsible Entity, and (iii) reevaluate the identified buses at least once every five calendar years. ". We are also concerned that this requirement envelopes 3 distinct and mutually exclusive requirements, each of which apply to distinct registered entities and each having different measures. This should be separated into three requirements which will also make the measures for VSL and VRF more applicable. The distinguishing of requirements for clarity in applicability and measurement should be included as an element of the "Quality Review" prior to industry comment posting. R5.1 - The BES Elements that require monitoring shall include the following...R5.2 - The BES Elements that require monitoring in each Responsible Entity's area shall include a minimum of...R5.1.4 requires monitoring BES Elements associated with IROLs. The requirement should only apply to IROLs that are voltage or stability limited: "One or more BES Elements associated with IROLs that are based on voltage or stability performance."

Response:

- **The use of "BES Buses" has been removed from the draft standard; the intent was to provide clarity, but actually resulted in confusion. The intent is that the Responsible Entity will determine BES Elements for which DDR data is required.**
- **Part 5.1.2 has been revised to remove market concerns, as well as to provide clarity: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."**
- **A description of the intended selection of IROL Element(s) has been added to the Guidelines section of the draft standard. The draft standard requires, "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for Cascading Outages. IROLs may be defined by a single or multiple monitored Element(s) and contingent Element(s). The Standard does not dictate whether the contingent and/or monitored Elements should be select; rather, the Standard Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL." The DMSDT has added this to the guidelines for Requirement R5.**

Organization	Yes or No	Question 2 Comment
• **Recommendations regarding the ordering and separation of the body into distinct requirement parts has been incorporated in the draft standard, separating those distinct components into parts of Requirement R5.**		
Seattle City Light	No	As for R1, R5 does not NERC principles for world-class Standards, because it includes three separately audited control activities in a single sentence: (1) identify Elements, (2) notify others of Elements, (3) reassess every five years. If this draft Standard is deemed necessary, Seattle recommends revising the first paragraph of R5 to include three subrequirements as follows: R5. Each Responsible Entity shall: R5.1 Identify BES Elements for which dynamic disturbance recording (DDR) data is required R5.2.Notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements may require DDR data R5.3 Reevaluate the identified buses at least once every five calendar years. And then renumber the remainder of the requirements to conform: 5.4 The BES Elements shall include the following: 5.4.1 Generating... In addition, the draft Standard does not clarify required actions should the five-year reassessment identify a different selection of Elements for which monitoring is required. Seattle suggests that an implementation period be identified for installing DDR capabilities for newly identified Elements similar to the implementation time for the initial implementation of the Standard. Likewise, the Standard does not clarify how newly constructed buses are handled. Seattle suggests that that they be evaluated at the next 5-year reassessment, rather than individually as they are brought on line.
Response: The SDT has revised R5 based on comments received. **The Implementation Plan addresses data capability for newly-identified buses and BES Elements: "Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." The Rationale Boxes for Requirements R1 and R5 explain the reevaluation interval – newly-identified BES buses and BES Elements are identified at the five-year reassessment.**		

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency	No	see question 3
Response: Thank you for your comment. Please see responses to Question 3.		
ACES Standards Collaborators	No	We disagree with the identification of BES Elements and the minimum BES Element criteria identified by the SDT. We feel that industry is capable of identifying the number of dynamic disturbance recording devices, "based upon [its] experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis." We believe this standard should require an entity to generate its own methodology to make these determinations and how often.
Response: Based on the Standard Drafting Team's experience with Disturbance Monitoring and event analysis, along with input from industry subject matter experts (SMEs), the DMSDT believes that the BES Elements outlined in the draft standard are essential for understanding a sequence of dynamic events and recreating those events in simulation to understand what happened and why it happened. The DMSDT believes that capturing these Elements will provide event analysis teams with the necessary measurements to accurately and systematically piece together large disturbances, such as blackouts or Cascading events effectively. Allowing each entity to develop their own methodology could lead to conflicting results.		
Duke Energy	No	(1) Duke Energy cannot envision the reliability benefit of including relatively low ATC as a consideration for the placement of DDR equipment in bullet 5 of R5.1.2. Duke Energy suggests the following revision:"5.1.2 Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines: o Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection, or o Transfer Paths in the Western Interconnection Path Rating Catalog, or o Voltage stability limited transfer paths or load serving area, or o Interfaces between Balancing Authority Areas, or o Areas of significant congestion or thermal violation history" If an entity is calculating ATC reliably, there should not be an area of significant congestion or thermal violation history due to the inherent

Organization	Yes or No	Question 2 Comment
		margins (TRM, CBM, etc.) that are built into the ATC calculation. In addition, the ATC consideration is redundant to the previous items in the same bullet.
Response: The Standard Drafting Team has revised Requirement R5 Part 5.1.2 to remove all commercial aspects from the requirement. Requirement 5 Part 5.1.2 now reads, "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
Bonneville Power Administration	No	BPA feels checks and balances need to be included to ensure Responsible Entities get concurrence from affected TOs/GOs that dynamic disturbance recording (DDR) data is needed at a given location. Additionally, an IROL is defined as in the Long-Term Planning Horizon, not in the operating horizon. BPA also believes R 5.1.5 needs clarification regarding the criteria for "major voltage sensitive area," - which is related to UVLS (for example, as represented by a metro area of 10 million people / 3000 MW). Otherwise, an isolated radial issue that doesn't impact the Interconnection may be erroneously specified.
Response: The Responsible Entity (RC or PC) assumes the responsibility for selecting BES Elements for DDR coverage because they have the best wide area view of the BES. It is expected that the RC or PC will work with the TOs/GOs to determine the most cost-effective and useful locations for DDR monitoring through the criteria put forth in this standard. The Standard Drafting Team does not feel that an upper threshold number of DDR be placed; this could lead to insufficient DDR applied to the BES, particularly in areas where DDR data would be valuable. It is expected and the intent of this standard that the flexibility provided to the Responsibility Entity can be used to leverage existing DDR equipment currently in operation and provide an adequate wide area view with respect to DDR data. **Regardless of the time horizon, if IROLs are exceeded then there is "… increased risk of voltage instability, Cascading Outages or uncontrolled separation that adversely impacts the interconnection." For this reason, the Standard Drafting Team feels that IROLs should be monitored for Disturbance Monitoring and event analysis purposes. Furthermore, in a NERC reference document (*Supporting Reference for Identification of Interconnection Reliability Operating Limits*), it states: "IROLs are monitored by the Reliability Authority. The [RA] may delegate this task to system operators working for entities performing the [TOP] function, but**		

Organization	Yes or No	Question 2 Comment
it is the [RA] that is held accountable for ensuring that IROLs aren't exceeded." This describes IROLs being monitored in Real-time to ensure they are not violated, just like System Operating Limits. **"Major voltage sensitive area," for the purpose of this standard, is meant to capture areas with in-service UVLS programs to avoid any ambiguity for what is "major voltage sensitive area." The rationale box has been updated to provide further clarification; the requirement has been modified to provide that clarification. However, the DMSDT avoided using ambiguous load density and/or power quantity thresholds. An "isolated radial issue that doesn't impact the interconnection" likely does not require a BES UVLS program to ensure voltage stability.**		
Ameren	No	(1) In addition to our comments we adopt the SERC PCS comments, and include them by reference. (2) As we have stated in our previous comments, we have installed over 30 PMUs on our system over the last 3 years in conjunction with our Planning Coordinator. This required significant effort and resources to perform this installation work. Even though they have not yet been needed for disturbance analysis, some operating visualization tools are being used and we have reviewed some minor perturbations. We respectfully disagree with the drafting team's brief justification in the Rationale for R5. We still believe the resultant number of PMUs which might be needed under the new standard would be burdensome to most entities. (3) Our software vendor has made known to us that they do not presently have the full capability as described in Requirement 11 implemented in our data concentrator software.
Response: **1. Refer to the Standard Drafting Team's response to the SERC Protection and Controls Subcommittee.** **2. After extensive outreach to industry, NERC Staff and subject matter experts in event analysis, the consensus is, and is opinion of the Standard Drafting Team, that there is insufficient wide area coverage of key Elements on the BES to facilitate accurate, effective and efficient analysis of cascading events or large disturbances. Examples of these types of events or other unexpected contingencies prove that DDR data can provide additional information otherwise currently unavailable to aid in understanding not**		

Organization	Yes or No	Question 2 Comment
only what happened, but why it happened; therein improving the reliability of the electric power grid. Per Requirement R5, your PC will be the Responsible Entity that will determine the DDR requirements. **3. It is important to note that the specifications outlined in Requirement R11 are not required of the vendors of the equipment used to capture the data. There are many offline tools currently in existence for purchase or developed by utility personnel for converting data into formats required for reporting. For example, data can be extracted from DDRs in their standard format such as C37.118 for synchrophasors, and then converted to COMTRADE format for reporting for the purposes of this standard.**		
Independent Electricity System Operator	No	(a) R5 is unclear as it mixes BES Buses with BES Elements. If the responsible entity (a PC or an RC) is to identify BES Elements for which dynamic disturbance recording (DDR) data is required, then it needs to notify ALL such Elements' owners, and there is no need to mention "of BES Elements connected to those BES buses". However, if the requirement is intended to ask the responsible entity to identify BES buses for which dynamic disturbance recording (DDR) data is required, then it needs to notify the owners of the BES buses AND the owners of the BES Elements connected to these BES buses. We suggest the SDT to review the intent of the requirement, and revise it to clearly convey the requirements on what is it the responsible entity needs to identify, and to whom it needs to notify. (b) Part 5.1.2: The term "significant Flowgates" is subject to interpretation since it is not clear what "significant" really means. We suggest the SDT to clarify this term or provide more specificity. (c) Part 5.1.4: It is not clear whether or not the BES Element associated with an IROL is the monitored element or the contingent element or both. This needs to be clarified. (d) Part 5.2: This part requires adding one BES Element for each additional 3,000 MW of an entity's historical peak system Demand, but the word "its" is unclear whether it means the responsible entity (in this case the PC or RC) or the BA. We suggest to reword it to clearly convey that it is the responsible entity's area historical peak system Demand. Note that additional clarity may be needed if the "its" refers to a PC or RC area since within a PC or RC area, there may be multiple BAs and TOPs within

Organization	Yes or No	Question 2 Comment
		which their system peak demand could occur at different times. Thus, Part 5.2 needs to clearly convey whether it is the total non-simultaneous peak demands of all BAs within an area, or it is the one-of highest demand of the entire area
Response: (a) Requirement R5 has been revised to clarify this issue by removing BES buses. (b) Requirement R5 Part 5.1.2 has been revised to remove all reference to commercial issues, and now reads: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)." (c) A description of the intended selection of IROL Element(s) has been added to the Guidelines section of the draft standard. The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for Cascading Outages. IROLs may be defined by a single or multiple-monitored Element(s) and contingent Element(s). The standard does not dictate whether the contingent and/or monitored Elements should be select; rather, the Standard Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL. (d) The ambiguous use of "its" has been removed and replaced with the explicit "Responsible Entity." In addition, the use of "simultaneous" peak system demand has been added to clarify that physical, actual coincident peak is to be used. Further information has been provided in the Rationale and Guidelines sections to help provide clarification and direction for applying this requirement's parts.		
City Utilities of Springfield, MO	No	The R5 language is confusing to me. It appears the Responsible Entity is charged with identifying Elements (not buses), but then the requirement language shifts to notifying owners of Elements connected to "those BES buses" and later reevaluating "identified buses". How are the buses "identified"? Is this an oversight based on the changes made to the earlier version of the Standard? Please clarify.
Response: Requirement R5 has been revised to clarify this issue. The intent is that the Responsible Entity will identify BES Elements for which DDR data is required. They will then notify the owner(s) of those particular Elements that DDR data is required as per this standard. The use of "BES buses" was to simply provide clarify but industry has commented that this is confusing and has thus been removed.		

Organization	Yes or No	Question 2 Comment
American Electric Power	No	While AEP has no disagreement with the Elements as specified in R5.1, the standard lacks clarity in what flexibility if any, the Responsible Entity has in selecting them. For example, the text "may require DDR data" implies some flexibility in that regard, and such flexibility should be made more explicit within the standard. It would be more clear if the minimums provided in 5.2 were provided *before* the Elements specified in 5.1 (essentially a swap of 5.1 and 5.2).
Response: The phrase "… may require DDR data" has been revised to "… require DDR data when requested." The intent is that the standard mandates that data be furnished when requested. But how that data is collected is up to the entity required to provide that data. The standard does provide a specific set of BES Elements for which DDR data is required and selected by the Responsible Entity. For example, "major voltage sensitive areas" and "One or more BES Elements" allows for flexibility in the selection of DDR data appropriate for regional variances and different topologies. In addition, the Elements requiring DDR data need not be directly measured and can be determined or calculated assuming this derivation is accurate and time synchronized. The issue of inclusion of Elements for Requirement 5 Part 5.1 and Requirement R5 Part 5.2 has been outlined in the Rationale section of the updated draft standard.		
Seminole Electric Cooperative, Inc.	No	See comments under Question 3
Response: Thank you. Refer to the response to Question 3.		
City of Tallahassee	No	see response for question 3
Response: Thank you. Refer to the response to Question 3.		
Kansas City Power & Light	No	See comments at end of form.
Response: Thank you. Refer to the response to Question 3.		

Organization	Yes or No	Question 2 Comment
City of Tallahassee	No	Please see comment for question 3.
Response: Thank you. Refer to the response to Question 3.		
Dynegy	No	The DDR requirements for GOs are more prescriptive than other regional Criteria or Regional Standards (i.e. NPCC). Recommend the 500 MVA limit be increased.
Response: The Standard Drafting Team used the NERC GADS database to perform a more extensive analysis of generating resource sizes to better understand the coverage requirements relative to the size thresholds to ensure a cost-effective means of capturing large generating resources without overburdening the entire generation fleet across the NERC footprint. This led the DMSDT to selecting the 500 MVA threshold, which the DMSDT feels is justified and representative of a good balance between reliability and cost-effectiveness. DDR data is critical to event analysis for understanding why generating resources do or do not respond as expected. This data provides useful information as to "why" not "when" the unit responds and/or trips based on the electrical characteristics it sees at its terminals. Recording, capturing, simulating and ultimately understanding these responses improves reliability of the BES and overall electric grid.		
Tacoma Power	No	It is unclear what requirements for DDR data changed. The redlined version has only superficial changes to Parts 5.1 and 5.2. Tacoma Power has some concern about the fourth bullet under Part 5.1.2: "Interfaces between Balancing Authority Areas." While this is only one guideline that the Responsible Entity should (not must) consider, it could potentially place disproportionate burden on entities with a relatively small Balancing Authority Area.
Response: Requirement 5 Part 5.1.2 has been revised for clarity to: "Any one BES Element that is part of a stability or voltage related System Operating Limit (SOL). "		
Entergy Services, Inc.	No	We agree with the revised DDR location criteria reducing the number of monitored BES Elements and appreciate the DMSDT efforts to address that issue. However we are still concerned about the potential for an unnecessarily excessive number of required DDR locations with regard to Flowgate applications. We believe the proposed minimum criterion of "One additional BES Element for each additional

Organization	Yes or No	Question 2 Comment
		3,000 MW of its historical peak system Demand." does specify a reasonable lower threshold which provides adequate wide area coverage and also believe there should be a similarly defined upper threshold on the number of DDR Flowgate (or DDR total) locations required. Suggest DDR Flowgate location criteria be revised to specify no more than twice the adequate minimum number of locations as follows: "Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection (prioritized by the Responsible Entity with area coverage considerations and with a total of no more than one BES Element per 1,500 MW of its historical peak system Demand),"
Response: The Standard Drafting Team has spent much time regarding the selection of DDR, while both specifying specific Elements and allowing for some flexibility. The Standard Drafting Team feels the draft requirement put forth finds a good balance regarding the selected Elements. An upper limit could hinder the capture of additional data in areas that would otherwise enhance and facilitate data analysis. The DMSDT has revised Requirement R5 Part 5.2 and added clarifications to the Rationale/Guidelines to indicate that Requirement 5 Part 5.2 sets a minimum set of BES Elements, while the BES Elements identified in Requirement R5 Part 5.1 are included in the minimum set by Requirement 5 Part 5.2.		
City of Tallahassee	No	see comment for question 3
Response: Thank you. Refer to the response to Question 3.		
Nebraska Public Power District	No	For R5 if the Responsible Entity is slow in notifying owners where DDR data is required does this force the owners to meet the same implementation deadlines or can they extend the deadlines by the same amount of time the RE was late in getting a notification out to the owners? I bring this up because the BES owners will not have any control over the RE schedules but could be subject to shorter implementation deadlines. In addition, since there is some open ended latitude in the ability of the Responsible Entity to identify locations for DDR it is possible that large number of locations could be identified to install DDR in some areas. If this were to occur would there be a possibility for the BES owners to request additional implementation time

Organization	Yes or No	Question 2 Comment
		to become compliant? Consider if some clarification could be added. One option might be to have criteria in 5.1.2 less open ended without any latitude.
Response: As per the Implementation Plan, the clock starts for implementation on the Effective Date of the standard. Any issues with meeting implementation deadlines would have to be vetted through compliance. The DMSDT had previously revised the Implementation Plan to accommodate outage schedules and implementation of all requirements. Requirement R5 Part 5.1.2 has been revised to eliminate any ambiguity, and now reads: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)." **This revision eliminates the latitude for the Responsible Entity to identify an abnormally large number of locations for DDR data.**		
Oncor Electric Delivery LLC	No	Oncor recommends an audit curtailment be added to the DDR requirement similar to what is used in Attachment 1 for the FR's and SER's.
Response: The DMSDT is not aware of any audit curtailments in Attachment 1.		
Ingleside Cogeneration LP	No	ICLP holds to its position that the 1500 MW criteria established in CIP Version 5 for Medium-Impact generation plants is also appropriate for the placement of Dynamic Disturbance Recorders. In our view, the survey that was performed by NERC when the cyber asset bright-line criteria was developed resulted in a reasonable balance between cost and reliability benefit. There has been no corresponding justification provided under Project 2007-11 that would indicate that the 1000 MW threshold is more appropriate.
Response: As stated in the Guidelines and Technical Basis section of the Standard, here is the technical justification: **Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a disturbance helps the analysis of large Disturbances. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those**		

Organization	Yes or No	Question 2 Comment
thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet: • The number of individual generating units in total included in the spreadsheet. • The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP. • The total number of units within selected size boundaries. • The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds. • The information in the spreadsheet does not provide information by which the plant location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility. From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA.” The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, Part 5.1.2 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. The incremental impact to the number of units requiring monitoring is expected to be relatively low.		
Northeast Utilities	No	
n/a	No	1. R5 is unclear as to whether the responsible entity needs to identify BES buses or BES Elements on which dynamic disturbance recording data would be required.

Organization	Yes or No	Question 2 Comment
		2. Part 5.1.4: It is not clear whether or not the BES Element associated with an IROL is the monitored element or the contingent element, or both. 3. The standard should not specify a number of BES elements (minimum or otherwise) for which DDR data is required. The number of Elements must be determined as those necessary to capture the necessary data to permit the complete study of key events in the BES and should not be pre-determined in the standard.
Response: Requirement R5 has been revised to clarify this issue. The intent is that the Responsible Entity will identify BES Elements for which DDR data is required. They will then notify the owner(s) of those particular Elements that DDR data is required as per this standard. The use of "BES buses" was to simply provide clarify but industry has commented that this is confusing and has thus been removed. **A description of the intended selection of IROL Element(s) has been added to the Guidelines section of the draft standard. The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for Cascading Outages. IROLs may be defined by a single or multiple monitored Element(s) and contingent Element(s). The Standard does not dictate whether the contingent and/or monitored Elements should be select; rather, the Standard Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.** **The minimum criteria is meant to ensure a wide area coverage of DDR data across all Responsible Entities; it is expected that this minimum criteria will be met with the BES Elements defined in Requirement R5 Part R5.1, which are defined because they are critical for wide area Disturbance Monitoring and event analysis.**		
PJM Interconnection	No	PJM signed onto the SRC's response to this question.
Response: Thank you for the comment. Please see responses to those comments.		
Austin Energy	No	City of Austin dba Austin Energy (AE), as noted below in the general comments section, does not agree with this standard as a whole. However, AE would like to point out a few clean-up items to Requirement R5. (1) R5 includes the phrase "notify

Organization	Yes or No	Question 2 Comment
		other owners of BES Elements connected to those BES buses". "[T]hose BES buses" implies reference back to BES buses cited previously in the requirement, but they do not exist. R5 requires the Responsible Entity to identify BES Elements not BES buses. The simple fix is to strike "connected to those BES buses." (2) AE believes R5 Part 5.2.2 would read better if the SDT changed the phrase "for each additional 3,000 MW" to "for every 3,000 MW." Otherwise, the Responsible Entity is left asking "in addition to what?"
Response: Thank you for the comment. Requirement R5 and its rationale box have been extensively revised, including Requirement R5 Part R5.2.2. We have removed references to BES buses and Requirement R5 Part R5.2.2 has been revised to "per 3,000 MW."		
CPS Energy	No	Main issue is that "Areas of significant congestion, thermal violation history, or relatively low ATC" is very vague.
Response: The bulleted components of Requirement R5 Part R5.1.2 have been removed and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
Avista Utilities	No	Requirement R5 has the Responsible Entity (WECC RC) determining the location of Dynamic Disturbance Recorders (DDR) based on the Western Interconnection Path Rating Catalog or interfaces between Balancing Authorities (BA). WECC has never provided reasoning or justification behind the paths and the selection of the facilities included in the paths. Also the BA does not own or operate any facilities. The more appropriate entity would be the Transmission Operator to determine the interfaces in the BES.
Response: The bulleted components of Requirement R5 Part R5.1.2 have been removed and replaced with: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."		
Dominion	Yes	

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	Yes	There should be consistency between Parts 5.1.2, 5.1.4, and 5.1.5. The Drafting Team in 5.1.2 and 5.1.5 require DDR on ANY ONE BES Element but in 5.1.4 it uses “One or more BES Elements...”. Reading the DT response to the last comment round it seems the intent was to be consistent for these three items; only one BES is required to be monitored. If true then standardize on ANY ONE BES element. Refer to the comments in Question 1.
Response: Thank you for the comment. These requirement parts are worded, by necessity, slightly different due to the criticality of an IROL.		
MRO NERC Standards Review Forum	Yes	
Colorado Springs Utilities	Yes	
SPP Standards Review Group	Yes	We suggest that the DMSDT further clarify the Applicability of the Functional Entities in 4.1 by including a statement in the Rationale Box for Functional Entities that when Responsible Entity is used in PRC-002-2, it specifically refers to those entities listed under 4.1. This is a slightly different approach than usually taken in Applicability.
Response: A statement in the Rationale for Functional Entities was included to provide further clarification, as requested. Thank you for your comment.		
Arizona Public Service Company	Yes	
FirstEnergy	Yes	
DTE Electric	Yes	
Bureau of Reclamation	Yes	

Organization	Yes or No	Question 2 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	
Wisconsin Electric Power Co	Yes	
Pepco Holdings Inc.	Yes	
Xcel Energy	Yes	We still believe the "Responsible Entity" should be consistent across the Interconnections. We recommend changing this to be the Reliability Coordinator for all Interconnections.
Response: The responsibilities of functional entities vary by Interconnection; and, therefore, the Responsible Entity is used to capture those variances. Referring to the NERC Reliability Functional Model, this type of analysis fits the PC better than the RC since it does not deal with ahead-of-time or Real-time functions. However, in certain areas/Interconnections, the RC is better suited to perform this analysis either through subcommittees, collaborations or internal staff.		

Organization	Yes or No	Question 2 Comment
Luminant Generation Company, LLC	Yes	
ITC	Yes	
CenterPoint Energy Houston Electric, LLC	Yes	
Exelon Companies	Yes	No Commnet
Texas Reliability Entity	Yes	We agree with the concept of the requirement, however, we suggest moving the methodology for selecting DDR locations described in 5.1 and 5.2 to an attachment and not include it within the text of the requirement itself (similar to the SER/FR bus selection methodology in Attachment 1 for R1).
Response: Attachment 1 is a multi-step mathematical methodology that needs to be separate from the body of the standard. Requirement 5 Parts R5.1 and R5.2 are written specifications that should remain in the body of the requirement to conform with the conventions of NERC Reliability Standards development.		
Idaho Power Co.	Yes	
Puget Sound Energy	Yes	
PNM	Yes	

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

Summary Consideration:

A number of stakeholders voiced their concerns for more precise wording of the Step 7 in Attachment 1 which stated "If the list has 11 or fewer BES buses: FR and SER data is required at the BES *buses* with the highest maximum available calculated three phase short circuit MVA." The ambiguity arose out of the term "buses" because it could be read as requiring FR and SER data from more than one bus. Thus, Step 7 is now revised to read "If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES *bus* with the highest maximum available calculated three phase short circuit MVA."

Several stakeholders also commented that Requirement R11 had no substantial impact on improving the reliability of the system. The DMSDT notes that the Requirement R11 ensures data availability from the data sources, timely retrievability of the data and common format so that the data can be read and used in the expeditious and effective analysis of events. Requirement R11 provides a reliability impact by integrating all of the previous requirements in the standard with respect to data reporting facilitate event analysis. The first two Parts of Requirement R11 specify how long an entity has to provide requested data (Part 11.1) and also limits how long data must be retained by the TO or GO (Part 11.2). Parts 11.3-11.5 ensure the uniformity and consistency of the data that is reported.

One technical change many stakeholders proposed was to revise Requirement R10 to relate to time synchronization of the device clock rather than data. The Requirement's original language called for time synchronization of SER data within +/- 2 milliseconds. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices are within ± 2 ms accuracy will suffice with respect to providing time synchronized data. The drafting team revised Requirement R10 accordingly.

Organization	Question 3 Comment
CenterPoint Energy Houston Electric, LLC	1) Regarding R2, CenterPoint Energy believes that breaker open/close operations obtained from the EMS system time-stamped based on RTU scan is adequate SER data for the initial stages of event analysis before detailed disturbance data is obtained from the FR and DDR data that is ultimately required for the actual event analysis. Therefore, CNP recommends removing SER data from R10. 2) Requirement R3 states "...shall have the following FR data to determine the following electrical quantities for each of the BES Elements they own connected to the BES Buses identified in Requirement R1:". CenterPoint Energy believes this language causes confusion with regard to "determining" phase-to-neutral voltages for each phase of each specified BES Bus as required by Part 3.1. The BES Bus voltage can be "determined" by measuring/recording each phase-to-neutral voltage of each line, or by measuring/recording each phase-to-neutral voltage of a smaller subset of lines connected to a BES Bus. The Guidelines and Technical Basis Section describe measuring voltages of "each" line. For entities that are using dedicated fault recording devices, channel capacity can be an issue. In some installations, voltages from 2 or more lines, i.e. a subset of the total number of lines connected to the BES Bus, can be recorded to provide adequate phase-to-neutral voltage FR data for system disturbances obviating the need to record each phase of each line at the recorder. CNP recommends that the DMSDT reconcile the Guidelines and Technical Basis Section language with the Part 3.1 language such that BES Bus voltages can be "determined" by measuring a number of line voltages based on engineering judgment.

Response:

1. SER is included in Requirement R10 to ensure accuracy to facilitate event reconstruction and analysis. The requirement has been revised to relate to time synchronization of the device clock rather than data. All modern digital SERs have an internal clock accuracy of much tighter than what has been specified in the standard.

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following specifications: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

Organization	Question 3 Comment
10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC. **2. The wording of the Guidelines for Requirement R3 was revised to: "Voltages are recorded or accurately determined at applicable BES buses."**	
Nebraska Pubilic Power District	It appears, for example, GSU 13.8kV generator buses that exceed the 1500MVA fault current level should be in the bus fault list for FR evaluation. If this is correct they are often ungrounded systems. Can the FR voltages and currents be monitored on the high side of GSU or a tie transformer with a BES tertiary reactor? It seems unclear what currents would be required to monitor as there would not be any ground current at these types of locations/buses if the ungrounded low side must be monitored. R3 and R4 don't specifically mention GSU transformers, GSU low side buses or BES tertiary buses which tend to be ungrounded systems. Can the drafting team clarify that for tertiary or GSUs where the generator bus (for example 13.8kV) is identified in the list of fault buses that it would be acceptable to monitor the voltages and currents on the high side of the GSU or tie transformer? If not, clarify that only the three 13.8 line to ground voltages or 13.8kV line to line voltages are required but not the currents or at least not the ground current. Note that the option of line to ground or line to line voltages is suggested above. Some ungrounded buses may not have line to ground voltages. This may be a concern for some utilities. It seems a bit odd the DDR would be allowed to be on the GSU high side yet still require FR data using the generator bus side voltages as the standard appears to read. R7 seems to address the high or low side requirements better for DDR but clarification for what is required for GSU and generator buses for FR would be helpful since they are often ungrounded systems. For R11 it states: "Each Transmission Owner and Generator Owner shall provide all SER, FR, and DDR data for the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 to the Reliability Coordinator". Consider clarifying this wording since it appears to require DDR data is required for R1 to be provided to the RC. R10 also appears to have this concern as well. DDR data is not required by R1, but through the use of the word "and" in R10 and R11 it appears that DDR recording may be necessary on these buses. R12: Is the CAP required to be submitted to the RE or is it upon request similar to the records? This requirement seems like it would be difficult to audit since it would be tracking work on a utilities

Organization	Question 3 Comment
	system. I wonder if the RE is prepared to monitor this information. If they do plan to monitor this is there any other process format or forms necessary or is it understood to be an informal case by case transmittal of CAP status?
Response: Requirement R1 and Attachment 1 applies to Transmission Owners and will exclude Generator Owner 13.8kV buses. **Requirement R11 and R10: The drafting team has revised the language to reflect your concern. Both requirements now read "…all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements…"** **The wording in Requirement R12 was revised to clarify that the CAP is to be submitted to the Regional Entity within 90 days and implemented as follows:** **R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]** • **Restore the recording capability, or** • **Submit a Corrective Action Plan (CAP), to the Regional Entity and implement it.**	
Luminant Generation Company, LLC	(1) Requirement R11, subsections 11.3, 11.4 and 11.5 includes prescriptive details regarding data recording and reporting. The goal of the standards development process is to develop Results Based Standards. These items are completely administrative in nature and are not results based. An entity could make a typo in formatting or when naming a file and be non-compliant with the requirement. These requirements should be removed from the standard or relocated to reference documents as described below. (2) Requirement R11, subsections 11.4 and 11.5 reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. Inclusion in a reference document seems to provide a better location to document specific details on requested data and can provide a more effective mechanism for revising these details at a later date in regards to the data reporting.

Organization	Question 3 Comment
	(3) Requirement R11, subsection 11.4 specifically references "IEEE C37.111-2013". Some older DFRs that effectively capture the needed data may not meet this requirement for the 2013 software update. Software updates may not always be reasonably accomplished with equipment, service contracts or other factors. This specificity is administrative in nature and does not contributed to a results based standard. This version requirement should be revised to allow for any software versions that the entity has access to that supports the recording and report requirements.
Response: **1. Requirement 11 Parts R11.3, R11.4, and R11.5 facilitate event analysis by ensuring the result of consistency in data to be reported.** **2. Regarding Requirement 11 Parts R11.4 and R11.5 are needed to ensure consistency in the data reported, the analysis of the 2003 Northeast Blackout was hampered by the inconsistent data formats presented to the investigators.** **3. Consistency in data format is important for efficient and expeditious event analysis. The standard does not require that the recording of data be done in a particular format. The data needs to be in the specified format and this can be accomplished for older formats using conversion software.**	
ACES Standards Collaborators	(1) We applaud the SDT's decision to remove the standard-only definitions provided in the previous draft revision. We also approve of the SDT's step to reduce the overall number of requirements listed in this standard. (2) However, we disagree with the SDT's claim that this standard addresses the "what" of data collected and not the "how" the data is collected. The costs of installing new equipment for the purposes of disturbance monitoring could be significant for some of our members. Moreover, industry has already benefitted from the DOE grants to install PMUs and would continue to benefit from these types of financial incentives for continual situational awareness. In its Consideration of Comments posted May 9, 2014, the SDT rebutted our previous submitted comments with references to the 2003 Blackout in the Northeast. However, it was through these financial incentives, that sufficient data was available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California Outages. As

Organization	Question 3 Comment
	stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, "PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP)." Moreover, the resulting report identified that no additional standards were necessary because of this event. We suggest NERC should develop a Reliability Guideline on this topic instead of a standard, as we do not see the cost benefit or justification to allocate resources for an issue that is not a high priority for reliability, such as cyber security. (3) We continue to have concerns that the SDT has not identified a transition period in the standard when a Reliability Entity identifies or receives notification that they are then required to install a recording device. The only transition period the SDT has accounted for is what the SDT listed in the Implementation Plan and based on the effective date of the standard. e(4) We disagree with the previous response to our comments from the SDT, as cited in its Consideration of Comments posted May 9, that "to facilitate expeditious and reliable data capture, it is necessary to stipulate the data formats necessary for efficient data analysis". We feel the SDT could incorporate such stipulation in a separate technical specification or even included as reference within the standard. We feel the technical specifications listed in Requirements R8, R9, R10, and R11 would further strengthen this case, and not subject registered entities to possible violations for every part of these requirements. We feel that technology has significantly improved since the 2003 Northeast Blackout, as manufacturers and industry have supported the need to align such devices on a common frame of time and develop related industry standards accordingly. The SDT even supports this later claim by directly referencing these standards in the text of this proposed NERC standard (see Requirement R11.4). (5) We believe numerous requirements of this Standards fall under Paragraph 81 Criteria B, and are thus unnecessary. We previously alerted the SDT to this observation and reference portions of its response, listed in its Consideration of Comments posted May 9, here. We concur with the SDT that "Disturbance Monitoring recording is necessary to ensure the reliability of the BES by providing the data for a post event analysis that can determine if system improvements are necessary to ensure reliability [and] guide real-time operating decisions." However, we disagree that these "supportive

Organization	Question 3 Comment
	requirements are necessary" and feel that the SDT should take some initiative. For reference, we re-list our observations below. (6) We feel Requirement R11 is arbitrary and could be subject to interpretation from auditors due to Paragraph 81 criteria. TOs and GOs could be required to prove the negative, and demonstrate that they have not received a request to provide device data to their RCs, Regional Entities, and NERC. Furthermore, this requirement meets several Paragraph 81 criteria including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. This requirement is administrative because it compels data formats that are immaterial to reliability with the sole purpose to simplify data collection and communication. It meets the data collection/data retention criterion because the requirement is about collecting data. It also meets the reporting criterion because it compels data reporting. We recommend the SDT should remove this requirement in its entirety. It would be more appropriate to include these specifications in a guideline. Furthermore, we feel portions of requirements R1 and R5 are "Periodic Updates" due to the need to reassess each list of affected BES Elements every five calendar years. Likewise, we feel requirements R1, R5, and R11 are "Administrative" due to the need to collect, organize, format, and then circulate data and communications sent to identified entities within a specific timeframe. We feel that several other requirements could be "Data Collection" in nature. Requirements R4.1, R4.2 require the collection of data according to specifications outlined for the minimum recording rate and data duration. Requirements R8.1 and R8.2 require the collection of data according to specifications outlined for the trigger record lengths and trigger settings. Likewise, Requirements R9.1 and R9.2 require the collection of data according to specifications outlined for input sampling rate and output recording rate. Requirement R10 requires the collection of data according to specifications outlined for time synchronization. Finally, we feel Requirement R12 is "Administrative" and "Documentation" in nature based on the need to circulate the discovery of device failure within a specific timeframe and provide a Corrective Action Plan to the Regional Entity if repair is outside this timeframe. (7) Thank you for the opportunity to comment.
Response:	

Organization	Question 3 Comment
1. Thank you for the comment. 2. The intent of Project 2007-11 is to ensure that there is adequate Disturbance Monitoring data available for event analysis. PMUs are considered DDR, but for a more complete analysis SER and FR data is also needed. SER and FR data is also useful to make Real-time operating decisions. DDR is particularly helpful to analyze generator trips. A guideline will not ensure that there is adequate data available for event analysis as guidelines are unenforceable. As a result of the 2011 Southwest Outage settlement, FERC requires additional PMUs to be installed for reliability enhancements. 3. The standard does not address “how” the data is recorded, and the Implementation Plan defines the requirements for recording capability. In the Implementation Plan, there is a statement regarding compliance for a reassessed list: “Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list.” This language is reflected in the revised Requirements R1 and R5. 4. The Standard Drafting Team discussed the importance of stipulating formats with event analysis SMEs, and, because of its importance, it was decided to incorporate those parameters in the standard. If the data specifications are included in a separate guidance document, there would be no requirement for consistent data to be available for analysis. 5. Thank you for the comment. 6. Uniform data formats are essential to expeditious and efficient data analysis. Because of its importance and necessity in the resulting capture of usable data, Requirement R11 will be maintained. Paragraph 81 is intended to provide an initial review of requirements that may not provide reliability benefit, it is not intended as a blanket reason to remove requirements from standards and is not used by auditors. PRC-002-2 is being developed as a result of an industry accepted recommendation from the 2003 Blackout Report: “Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed. A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices.” NERC Planning Standard I.F — Disturbance Monitoring does require location of recording devices for disturbance analysis. Often time, recorders are available, but they are not synchronized to a time standard. All digital fault recorders, digital event recorders, and power system disturbance recorders should be time stamped at the point of observation with a precise Global Positioning	

Organization	Question 3 Comment
Satellite (GPS) synchronizing signal. Recording and time-synchronization equipment should be monitored and calibrated to assure accuracy and reliability. **Time-synchronized devices, such as phasor measurement units, can also be beneficial for monitoring a wide-area view of power system conditions in real-time, such as demonstrated in WECC with their wide area Monitoring System (WAMS).** **Recommendation 12a: The reliability regions, coordinated through the NERC Planning Committee, shall within one year define regional criteria for the application of synchronized recording devices in power plants and substations. Regions are requested to facilitate the installation of an appropriate number, type, and location of devices within the region as soon as practical to allow accurate recording of future system disturbances and to facilitate benchmarking of simulation studies by comparison to actual disturbances.** **Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization and, as necessary, install additional dynamic recorders."** **7. The Drafting Team thanks you for your comments.**	
Texas Reliability Entity	1. R1 VSL - The percentage and time basis language in the first two parts of the VSLs are confusing: it's unclear what the percentages are referring to and what time period the assessment is being measured to. Also, the term assess is not used in the requirement or Attachment 1. The third part of the VSL is clear. Suggestion to change VSL language for the first two parts to the following language across all severity levels in the table: "The Transmission Owner identified BES buses as directed by Attachment 1 for more than 80% but less than 100% of the BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement 1 but was late 30 calendar days or less for the once every five year requirement." 2. R5 VSL - The percentage and time basis language in the first two parts of the VSLs are confusing: it's unclear what the percentages are referring to and what time period the assessment is being measured to. Also, the term assess is not used in the requirement or Attachment 1. The third part of the VSL is clear. Suggestion to change VSL language for the first two parts to the following language across all severity levels in the table:" The Responsible Entity identified the BES Elements as directed by Requirement R5 for more than 80% but less than 100% of the BES Elements included

Organization	Question 3 Comment
	in R5.1. OR The Responsible Entity evaluated the BES Elements as directed by Requirement 5 but was late 30 calendar days or less for the once every five year requirement.” 3. For R3.1 - Attachment 1 states that a ring bus or breaker-and-a-half bus are considered as a single bus. Will the SDT please clarify does this mean that in a ring or breaker-and-a-half substation, only one bus needs to monitored for R3.1? 4. For R11 - We suggest moving the language describing specific formatting requirements in R11.3 through R11.5 to the Guidelines and Technical Basis section of the standard as it is administrative in nature and not performance-based. 5. For R12 - Has the SDT discussed having the entity reporting FR/SER/DDR failures report to the Responsible Entity as well as the Regional Entity, so that the Responsible Entity can look at possible alternative methods to monitor the Elements identified per R5? There may be a reliability gap if the Responsible Entity is not notified due to no requirement for the GO or TO to do so. 6. R11 VSL - The Requirements refer to days and the VSL language refers to percentages. We ask the SDT to confirm that the interpretation of R11 VSLs below is correct. If so, we suggest changing the VSL language to the language provided below. If not, please provide the correct interpretation and possibly revised language to help assure there aren’t inconsistencies in compliance and enforcement application. Lower VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 9 days but less than 10 days of the requested data. Moderate VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 8 days but less than 9 days of the requested data. High VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 7 days but less than 8 days of the requested data. Severe VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided less than 7 days of the requested data.
Response: 1. The wording of the VSLs for requirement R1 were revised to reflect revisions to the requirements as well as to add clarifications that you requested.	

Organization	Question 3 Comment
2. The wording of the VSLs for requirement R5 were revised to reflect revisions to the requirements as well as to add clarifications that you requested. **3. For monitoring any particular BES Element, you must be able to determine the appropriate voltages per Requirement R3.** **4. Requirement R11 Parts R11.3, R11.4, and R11.5 will remain with the standard. They are important to the effective analysis of system disturbances. Requirement R11 Parts R11.3, R11.4, and R11.5 facilitate event analysis by ensuring the result of consistency in data to be reported.** **5. The Standard Drafting Team discussed the submission of Corrective Action Plans to the Responsible Entity. It was decided to just have the CAPs go to the Regional Entity because the Regional Entity is in a better position to have an overview of the data recording capability for its area.** **6. The time period in Requirement R11 Part R11.2 does not refer to a quantity of data, but to the time period that the required data must be retrievable for. The percentages refer to how much of the sought after data was produced. The wording of the VSLs for Requirement R11 were revised for clarification by removing the reference to Requirement R11 Part R11.2.**	
Manitoba Hydro	1. Implementation Plan- The first paragraph simply describes a date that is synonymous with the Effective Date of the Standard. Accordingly, Manitoba Hydro recommends that this paragraph be abbreviated and made consistent with the third paragraph, by stating that:" Entities shall be 100% compliant on the Effective Date." 2. Similarly, the second paragraph under Implementation Plan describes a date that is three months after the Effective Date of the standard. Manitoba Hydro recommends that the wording be revised to state that: "Entities shall be 100% compliant within three months after the Effective Date. 3. R1 requires transmission Owners to notify other owners that certain BES Elements may require SER/ FR data within 90 days, however it does not specify when the 90 day period runs from. This could be interpreted as running from the Effective Date of the standard or from the day that the BES Element is identified(which could be prior to the Effective Date given that entities must be compliant with applying the methodology and identifying BES busses for which data is required as of the Effective date) . Manitoba Hydro therefore recommends that the ninety day period be clarified.

Organization	Question 3 Comment
	4. R5-(i) For the same reasons stated above, Manitoba Hydro recommends that the ninety day period be clarified. (ii) The contents of the notice to other owners (i.e. that certain BES elements “may” require data) conflicts with R7 which “requires” that an owner who has been notified to determine certain electrical quantities. Therefore, Manitoba Hydro recommends that the “may” in R5 be deleted.
Response: **1., 2.--The Effective Date section addresses the standard as a whole. The subsequent paragraphs refer to different requirements.** **3. The Requirement R1 wording says that Transmission Owners will identify the BES buses, and notify other owners within 90 calendar days. The clock starts when the Transmission Owner identifies the BES buses that have BES Elements connected to it that are owned by others.** **4. Refer to the preceding regarding the ninety-day comment. Requirement R5 stipulates that the Responsible Entity determines the BES Elements for data and has been extensively revised. The DMSDT has removed “may” from R5. Requirement R7 is needed to further specify what data is being looked for.**	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	a. Requirement R11, subsections 11.3, 11.4, and 11.5 do NOT have any impact on the reliability of the system. They are, in fact, entirely administrative in nature. The Results Based Standard template does not support including a requirement of these types. Efforts have been made to remove administrative-type requirements from standards. In this case, a simple mistake in formatting or when naming a file would result in non-compliance with the requirements. b. The GO requirement responsibility should be limited to making available signal sources to the adjoining TO’s for the specified list of signals of interest at generating stations. In most cases the TO already owns DM equipment while the GO does not. c. We remained concerned about the cost of the needed equipment where it does already exist; but, we thank the SDT for stretching out the implementation plan which will allow the cost to be allocated over a longer period of time.
Response:	

Organization	Question 3 Comment
a. Formatting and naming were specified to ensure uniformity in recorded data submission to facilitate event analysis. **b. The standard is just concerned with "what" data is captured, not "how" the data is captured. If the Transmission Owner owns DM equipment on the high side, then the Generation Owner may coordinate with the Transmission Owner for data applicable under the standard. Ultimately, the GO is responsible for having the data to be able to determine the applicable quantities under this standard as the existence of the generator necessitates the need for the DDR data.** **c. Thank you for the comment.**	
Wisconsin Electric Power Co	o R1: We suggest that the intent should be that the buses selected according to Attachment 1 will only be those that operate at or above 100 kv ? We believe that this should be specified in Attachment 1. o R2: The Measure M2, Part (1), should be changed to “documents describing the device interconnections and configurations which MAY include a single design standard as representative for common installations... “. This will provide greater clarity that a single design standard is sufficient for evidence, but that it is not required. o R2, Measure M2: In addition, as acceptable evidence, the list in M2 should also include “station drawings” as allowed in M10. o R3: The Measure M3, Part (1), should be changed to “documents describing the device specifications and configurations which may include a single design standard as representative for common installations;”, similar to the wording in R2. As written, the Measure would require entities to have a “single design standard”, which is not part of the standard Requirements. In addition, a new Part (3) should be added to allow “station drawings” as permissible evidence o R3 and R4: The Generator Owner is listed here, but it is not clear what requirements apply to it, if it does not own any equipment listed in 3.1 or 3.2. In light of the SDT’s statements about the superiority of dynamic disturbance recording for generators, we strongly urge that the applicability of R3 and R4 for Generator Owners be removed. o R4: The Measure M4, Part (1), should be changed to: “(1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3)”...

Organization	Question 3 Comment
	o R7: "Each Generator Owner shall have DDR data for each BES Element it owns and is notified according to Requirement R5, to determine the following electrical quantities..." This wording is not clear. We suggest using wording, similar to R6, "Each Generator Owner shall have DDR data for each BES Element it owns for which it received notification as identified in Requirement R5, to determine the following electrical quantities..." o R7: In Measure 7, Part (1), we suggest changing to : "(1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations;" This will allow needed flexibility in providing reasonable evidence. o R8: In Measure 8, make the same change as described above in M7. o R9: The Measure 9, Part (1), should be changed to: "(1) documents describing the device specification, configuration, or settings". o R10: The Measure 10, Part (1), should be changed to: "(1) documents describing the device specification, configuration, or settings". o Guidelines and Technical Basis Section , Guideline for Requirement R2, two statements are made that are at least unclear, if not contradictory: "SER data for generator breaker operations provides little useful data of generator loading." "Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers connected to the Transmission Owner's bus". Please clarify or revise as necessary.
Response: Buses used in Requirement R1 are identified as BES buses, and will have to conform to the definition of BES. The voltage level does not have to be specified in Attachment 1. **The wording of Measure M2 was revised, as requested.** **The wording of Measure M3 was revised, as requested.** **Generator Owner is used in Requirements R3 and R4 because a Generator Owner may own BES Elements connected to the BES buses identified in Requirement R1.** **The wording of Measure M4 was revised, as requested.**	

Organization	Question 3 Comment
The wording of Requirement R7 was revised, as requested. **The wording of Measure M7 was revised, as requested.** **The wording of Measure M8 was revised, as requested.** **The wording of Measure M9 was revised, as requested.** **The wording of Measure M10 was revised, as requested.** **In the Guideline for Requirement R2, SER data for a generator breaker just gives the breaker position, and not the generator's load. For disturbance analysis, it is important to know the position of every breaker connected to identified BES buses.**	
Springfield Utility Board	o Requirement 4, specifically 4.1, requires a single record or multiple records that include "a pre-trigger record length of at least 30 cycles for the same trigger point, or at least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder." This 32-total cycle creates a limit on SUB's ability to store event reports, and we assume is does for many others, as well. Much of the commonly used and standard software, including that used by Springfield Utility Board, utilizes a 30-cycle event report (2 cycles pre-fault and 28 cycles post-trigger. It does not seem unreasonable to change the language from 32 cycles to 30, so that entities will not incur the unnecessary expense of either purchasing new software or developing a work-around with their current software. o The "buses" language in Attachment 1, Step 7 should be clarified. SUB believes it should read "bus" and not "buses".
Response: The overall record length of 32 cycles is commonly employed in industry, and is not an unreasonable specification. Requirement R4 Part R4.1 allows for multiple records, as noted in the second bullet: "At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder." **The wording in Attachment 1, Step 7 was revised, as suggested.**	
American Electric Power	AEP believes that the wording of requirement R11.2 clearly conveys the drafting team's intent that an entity is not required to retain more than 10 days of disturbance monitoring data at any point in time. Unfortunately, this intent is blurred by the Compliance Evidence Retention's opening

Organization	Question 3 Comment
	paragraph and the statement that "The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12... for three calendar years." The Evidence Retention, as written, could be interpreted as requiring an entity to maintain three or more years' worth of SER, FR and DDR data. The issue is further confused by the proposed PRC-002-2 RSAW in which the Evidence Requested and the Compliance Assessment Approach for R2, R3, R4, R8, R9, R10 and R11 indicate that SER, FR and DDR data is required to demonstrate compliance and imply that an entity is required to keep all SER, FR and DDR data within the audit window. AEP believes that retaining years of disturbance monitoring data is overly burdensome, provides little to no benefit to reliability and is not the intent of the drafting team. The standard should be revised to align the Compliance Evidence Retention with the Requirements and to more clearly convey the 10 day data retention requirement. The Implementation Plan includes the following "Entities shall be 100% compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." We agree with this statement, but believe it would be more appropriate to include it within the Standard itself, rather than only within the Implementation. R1: The SDT should clarify who takes the lead role to notify other owners when there are multiple owners of a bus. Presumably it would be the company identified as the owner in the fault model being used but this should be clarified. Also, notification alone should not be sufficient in identifying monitored buses. There should be agreement from all owners that a bus should be monitored before it is included in the monitored list, unless it is in the top 10% which indicates it *must* be monitored. R2: It is unclear from the wording of R2 whether the TO/GO must monitor all circuit breakers connected to an identified bus or only circuit breakers connected to the identified bus that are associated with a BES Element. For example, would a 138 kV circuit breaker for a radial fed station service transformer be required to be monitored if it is connected to a selected bus? In this case, the station service transformer would not be a BES Element. We do not believe it would be appropriate to require SER or DFR data in this scenario, but the standard does not explicitly prevent such an interpretation. We suggest making it clear that the element is *both* connected directly to

Organization	Question 3 Comment
	the BES buses identified in Requirement R1 *and* associated with the BES Elements at those BES buses identified in Requirement R1. R3: The Application Guide implies that GSU leads are not considered lines for this standard. The requirement should be revised to clearly indicate this. Similarly, station service or reserve transformers should likewise be explicitly excluded. R3: The callout for R3 states "The required electrical quantities may either be directly measured or derivable if sufficient FR data is captured". The allowance for derivable methods is specified only in the callout, and is not explicit within the standard itself. This allowance needs to remain somewhere in the standard. Guideline for Requirement R3: We are confused by the exclusion "For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator in case of fault on the transmission system will be captured by FR data on the transmission system." We do not understand how the generation currents could be calculated from the transmission currents for faults on the interconnection. In addition, is it the drafting team's intent to exclude most generating units from fault recording? R12: We see no reliability benefit in sending all CAP's to the Regional Entity, and recommend revising it in consideration of Paragraph 81. Rather, it should be acceptable to only require the TO/GO to develop and execute a CAP and to make this information available to the RE within 30 calendar days of a request. AEP recommends revising the purpose statement to read "To ensure adequate data is available to NERC to facilitate event analysis of major BES disturbances. AEP recommends establishing only 5 requirements. There should be a requirement for each of the main objectives (establish a data set for FR/SER, establish a data set for DDR, provide FR/SER data upon request, provide DDR data upon request), and a single requirement for repair. AEP recommends modifying R1 so that the notified entity has the option to monitor either the local or the remote terminal of the subject Element. AEP recommends modifying R2-R4 and R6-R11 to clearly exempt data lost due to an equipment failure properly identified per R12.

Organization	Question 3 Comment
	AEP recommends modifying R3 so that only 3 of the 4 currents are required to be recorded. Since the fourth current can be calculated by the other three, there is no reliability impact for recording only three currents.

Response: The intent of the retention period is for the entity to retain the data that has been requested for a disturbance only. The DMSDT has revised the Data Retention section to:

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The drafting team has added a reference to the Implementation Plan in Requirements R1 and R5.

Regarding Requirement R1, Transmission Owners have to communicate the ownership of BES elements connected to a BES bus. The Standard Drafting Team discussed having a "lead" Transmission Owner. It was decided that that would lead to unneeded complexities in the requirement. Specifying agreements is outside the scope of this standard.

Regarding Requirement R2, the Rationale Box for R2 explains: "The intent is to capture SER data (opening/closing) for the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus."

Requirement R3 only applies to BES buses or BES Elements. The DMSDT believes that the requirement is clear as written. Also, the requirement was revised to explicitly state the TO/GO "shall have FR data to *determine* the following electrical quantities…" The drafting team revised the rationale to replace "derivable" to "determinable."

For faults on the Interconnection to generating facilities, the FR data from the transmission substation will capture enough data whereby the data for flow down the Interconnection can be calculated using Kirchoff's Law. Generating units are not included in the FR data capture capability.

Requirement R12: The Standard Drafting Team felt that it is important that the Regional Entity be aware of data recording capability that was out of service. The requirement allows 90 calendar days to determine a timeline for repair or replacement and for a CAP to be submitted to the Regional Entity. The requirement was revised to:

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

- **Restore the recording capability, or**
- **Submit a Corrective Action Plan (CAP), to the Regional Entity and implement it.**

Organization	Question 3 Comment
The Purpose reflects the importance of entities having adequate data recording capability to facilitate their own analysis of events, and develop solutions to prevent those events from recurring. It is beneficial for generators to have DDR to analyze why machines tripped or how they behaved during system disturbances. The Standard Drafting Team combined and edited requirements from the November posting to reflect comments received. The remaining requirements reflect the Standard Drafting Team supporting the Purpose of the standard. The Rationale Box for Requirement R3 explains the need for the three phase currents and the residual or neutral current. Note that Requirement R3 reads "...to determine the following electrical quantities..."	
Northeast Power Coordinating Council	An additional implementation requirement or effective date should be included to address the situation when after the 5 year evaluation an additional element is identified for FR or DDR to afford the TO or GO to budget and install additional equipment. The draft PRC-005-X standard included language to address this in its latest draft. Consider adding to the technical guidelines for R6 more information surrounding the allowance for the use of a common bus voltage measurement where appropriate to monitor multiple BES Elements. Suggest adding to the second paragraph in the guideline for R6: The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the Standard is not to require measurement of each BES Element where a common bus measurement is available. Where a common measurement is utilized the Owner must plan the installation such that a bus outage would not result in the DDR data to be compromised. For example,...etc..... Part 11.4 requires the use of C37.111-2013. This could be an issue if an Entity has not upgraded its equipment of firmware. In R8 an exception is allowed for DDR owners with older equipment. A similar tack should be applied here. The Standard should not force replacement. Attachment 1 does not specify how to distribute an odd number for 20% of the BES buses between 10% of the BES buses and additional 10% of the BES buses (both determined in Step 6), e.g. if twenty-one (21) buses in total are required.

Organization	Question 3 Comment
	Requirement R8 should allow legacy equipment to have multiple triggered records which when combined into one time synchronized record make up the required length of three minutes. Requirement R11, Part 11.3 requires SER data in Comma Separated Value (.CSV) format following Attachment 2 whereas the majority of Disturbance Monitoring Equipment (DME) does not save data in this format. Can the Drafting Team provide a name of DME which gives the data in this format? Requirement R11, Part 11.4 requires FR and DDR data in C37.111 (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE) formatted files whereas the majority of DME equipment does not save data in this format. Are manually converted records acceptable? Requirement R11, Part 11.5 requires data files to be named in conformance with C37.232 IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME) whereas the majority of DME equipment does not save data in this format.

Response: It is stated on Page 4 of the Implementation Plan that: "Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list."

The drafting team added the sentence, "The intent of the Standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available." The DMSDT did not believe that the second sentence is necessary as a lead-in to the example.

The drafting team agrees that there is inconsistency between requirements for using older equipment and data format. The version of COMTRADE has been revised to 1999 or later.

Whether an odd or even number of buses should not affect the distribution of buses. The requirement is for a minimum of 20 percent so you need to round up.

Combining multiple triggered records to one time synchronized record of at least three minutes in length is acceptable.

The drafting team can provide manufacturer information, but does not believe it is appropriate to provide that in a public record. Feel free to contact a member of the team for this information. The format specified in Requirement 11 Part R11.3 is for

Organization	Question 3 Comment
consistency. The standard addresses "what" data is captured, not "how" it is captured. The equipment to capture the data to conform to the standard is readily available. **Regarding Requirement 11 Part R11.4, manually converted records are acceptable, as long as the data is submitted in the specified format.** **Regardless of the file naming convention of your equipment, for consistency, submitted data files are to be named in accordance with Requirement 11 Part R11.5. You may save your files internally using any file naming convention you desire.**	
Peak Reliability	Applicability section: the Responsible Entity in all Interconnections should be the Planning Coordinator or Reliability Coordinator. R5.1.2, bullet 1, the term “significant Flowgates” appears to be undefined. Does it need to be clarified? R8: undervoltage trigger set no lower than 85% of normal operating voltage - what is normal operating voltage? For a 500 kV system, is it 500 kV or is it the average bus voltage for a specified period of time (such as 525kV)?
Response: Applicability: The responsibility of determining these locations fall on the PC, per the Functional Model. In some areas, this responsibility has been assumed by the RC and that is reflected in the applicability for the standard. **Requirement R5 Part R5.1.2 – all flowgate information has been removed. Requirement 5 Part R5.1.2 now reads “Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).”** **Requirement R8: The normal operating voltage is intended to be what voltage a system would normally be operated based on scheduled voltages.**	
Dominion	As stated in Dominion’s previous comments: “PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability

Organization	Question 3 Comment
	Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01).” The standard drafting team (SDT) in response provided:” The DMSDT is aware that the NPCC DMSDT has been reconvened to review the Regional Standard with respect to PRC-002-2 after it is approved.” While Dominion appreciates the SDT response, the fact remains that NPCC applicable entities continue to implement the FERC approved NPCC Regional Reliability Standard that could result in over/under installing DM capability when compared to PRC-002-2, once approved. Therefore, Dominion again urges the SDT to include a Variance in PRC-002-2 that excludes entities subject to PRC-002-NPCC-01 from the applicability section of this standard.
Response: The Standard Drafting Team has taken into consideration the approved and in-place NPCC PRC-002-NPCC-01. The Standard Drafting Team is aware that PRC-002-NPCC-01 applies to the BPS as defined in the NPCC A-10 Criteria. While that is not as comprehensive as the new BES and in force BES definition, PRC-002-2 is about "what" data is captured, not "how" the data is captured. It is impossible to make a blanket statement that meeting the requirements of PRC-002-NPCC-01 will meet the requirements of PRC-002-2. The Standard Drafting Team is sure that at the least, meeting PRC-002-NPCC-01 will provide a very good foundation for having the capability to capture the data asked for in PRC-002-2. If "over installing" Disturbance Monitoring capability was done, from an engineering and operations perspective that is only positive. The DMSDT is coordinating with NPCC to retire PRC-002-NPCC-01 upon approval of PRC-002-2.	
American Transmission Company, LLC	ATC asks that the SDT consider the following recommended changes to add clarity to the subrequirements: R5.1.2, bullet 1 - Add “as judged by the Responsible Entities,” to end of statement. R5.1.2, bullet 4 - Add “(not local Balancing Authorities)” after “Balancing Authority.” R5.1.2, bullet 5 - Add “as judged by the Responsible Entities,” to end of statement. R5.2.2 - Add “within the past 10 years” to the end of statement for time clarity.

Organization	Question 3 Comment
Response: Regarding Requirement 5 Part R5.1.2, the bulleted list has been deleted and the language is now "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)." **It is not necessary to be restrictive on the time frame for the historical peak system Demand in Requirement 5 Part R5.2.2.**	
HHWP	Attachment 1, Step 7 states: "If the list has 11 or fewer BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9."It seems that word "buses" in this sentence should be changed to "bus".
Response: "Buses" was changed to bus.	
ISO RTO Council Standards Review Committee	Attachment 2: acceptable states are OPEN or CLOSE but other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also commonly used. The format should allow for regional variations in terminology. Otherwise, it could become time consuming for TOs and GOs to provide the SER data.
Response: The DMSDT agrees and has revised the footnote in Attachment 2 to read: OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.	
Bonneville Power Administration	BPA does not believe the Cost Effective Analysis Process (CEAP) uses an appropriate comparison example, without clarifying between the 2003 Interconnection wide-area, numerous-state blackout and the 2011 local-area, three-state blackout within an Interconnection, as the 2011 event would naturally take less time and data. BPA does agree, however, with the synchrophasor (PMU) data-speed impact.
Response: Thank you for the comment.	
Austin Energy	City of Austin dba Austin Energy (AE) does not agree with this standard as a whole. AE believes it is too prescriptive and unnecessary in the ERCOT region. Regional requirements for ERCOT regarding disturbance monitoring equipment exist in the ERCOT Nodal Operating Guides, Section 6.1.

Organization	Question 3 Comment
	(http://www.ercot.com/mktrules/guides/noperating/cur). Existing requirements provide sufficient data for disturbance monitoring.
Response: Thank you for your comment. The standard drafting team notes that the ERCOT Operating Guide is not a standard and is not enforceable. PRC-002-2 is a proposed mandatory standard and its requirements were directed at "what" data is captured, not "how" it is captured.	
Puget Sound Energy	Could we use one BES location for both DDR equipment and FR/SER equipment?
Response: As long as the standard's requirements are met, one location could be used for SER, FR and DDR capture.	
Entergy Services, Inc.	Entities with a significant number of DDRs and have DDRs which include installations where manual data retrieval is necessary should be allowed more than 30 days to collect, format, assemble and review data for submittal. Add provision for a data request submittal extension such as "R11.1 The recorded data will be provided within 30 calendar days of a request unless an extension is granted by the requesting authority."
Response: The Standard Drafting Team has added your requested language to Requirement R11 Part R11.1 regarding an extension.	
CPS Energy	First issue is that we find the methodology for determining which BES busses may require SER or FR data to be overly complicated and difficult to follow. If the methodology is going to be this complicated, then perhaps the Planning Coordinator or Reliability Coordinator is best suited to perform this analysis so that Transmission Owners do not fall out of compliance for failing to understand an overly complicated spreadsheet with more than 17 steps to determine which busses require this equipment. The second issue is with the requirement of time synchronizing SER data to within +/- 2 milliseconds. While the intent of the standard appears to be to allow many modern existing relays that sample waveforms at 16 samples/cycle, have SER capabilities, and can synchronize to a GPS clock within less than 1 millisecond, this requirement will actually prohibit many of the relays because of the SER requirement. For example, a widely used SEL-311C relay can have its clocked

Organization	Question 3 Comment
	synced to within 1 microsecond, the SER is only time-stamped once every quarter cycle, which is the processing interval of the processor. This means that the SER can only be accurate to within +/- 5 milliseconds. We think this may not be realized by the drafting team and/or many stakeholders. Additionally, we believe that the +/- 5 millisecond accuracy should be more than accurate enough if only a breaker status is required by SER. Two things to note: 1) the breaker 52a or 52b contact that would be input into the DFR device is a mechanical moving device that in and of itself may not be that accurate in regards to an actual indication as to whether the breaker is open or closed. These contacts can often be adjusted as to when they make and occasionally are even wrong in regards to status. 2) Each breaker requiring SER is in many cases already being monitored for currents that give a change of status as to the breaker being open or closed.
Response: The Transmission Owner is the appropriate entity to perform the analysis for BES buses because the Transmission Owner is more familiar with the intricacies of its system than the Planning Coordinator or Reliability Coordinator. **Requirement R10 has been revised to relate to time synchronization of the device clock rather than data. All modern digital SERs have an internal clock accuracy of much tighter than what has been specified in the standard.** **"R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following specifications: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]** **10.1 Synchronization to Coordinated Universal Time (UTC), with or without a local time offset.** **10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC."** **The Standard Drafting Team acknowledges that the auxiliary switch or other inputs to SER for breaker status are not precise. Current through a breaker may be zero without a breaker opening. Breaker position status data is necessary for disturbance analysis. For multiple feeder tripout disturbances, circuit breaker SER data has been useful in making timely restoration decisions.**	
Associated Electric Cooperative, Inc. - JRO00088	FOR: Appendix #1, Step 6, Paragraph 2REPLACE: "buses with the highest" WITH: "bus with the highest" RATIONALE: Clarity - As this process step seems to yield one identified bus, presumed to

Organization	Question 3 Comment
	fill the void of its successor bullet's 10% minimum count, the use of "required at" in conjunction with "buses" is confusing. FOR: PRC-002-2, R5.2, Guidelines ECI believes the guideline for 5.2 should provide sample calculations for the number of DDRs required: 1) for an entity having 5999 MW Historical Load, and 2)for an entity having 6000 MW Historical load. While we believe the answer for 1) is only 1 DDR, and for 2) 2 DDRs per R5.2, the Webinar presenter mentioned some expectations for Rounding which introduced uncertainty that the above example could address.
Response: The drafting team has revised "buses" to "bus" as requested. **Requirement R5 Part R5.2: Your answers are correct. Part 5.2 has been revised to:** **5.2 Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:** **5.2.1 One BES Element** **5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak system Demand.**	
Oncor Electric Delivery LLC	General: It is understood the Rationale Boxes will be retained but relocated to the "Guidelines and Technical Basis Section" of the Standard. If the "Guidelines and Technical Basis Section" cannot be used as compliance validation to auditor(s), it is imperative the requirement language be paired to the alternatives specified in the Rationale language. Oncor identified several instances where the Rationale Boxes provided much needed clarity to the Requirement itself. Incorporating the Rationale/intent language into the Requirement or Measurement itself would further clarify the Requirements resulting in a clear and mutual understanding for both the Registered Entity and the auditor(s). Therefore, Oncor recommends the DMSTD review the Requirement/Measurement language and the corresponding Rationale language to ensure there are no gaps. Specifics are provided below: R2: Legacy FR equipment installed before the Standard effective date may not be capable of embedded SOER. R2 does not afford the same caveat for older equipment where SOER is required that R8 provides for older equipment where DDR is required. Language should be added to R2

Organization	Question 3 Comment
	providing the option to utilize FR digitals to monitor circuit breaker position for required circuit breaker position monitoring.R1 and R5: The Implementation Plan includes specific references to timeframes for becoming fully compliant with the locations lists after approval of the standard, but the Requirement language itself does not include post-implementation "5 year re-evaluation" compliance timelines for the required reassessments. "Re-evaluation time frame implementation" language should also be included in the affected Requirements to prevent any disparity following the initial implementation and departure from the Implementation Plan. R3 and R6: A Rationale should be added that the required "electrical quantities can be determined (calculated, derived, etc.)" to R3 and R6 as described below: o The R3 Rationale explains the method of deriving electrical quantities. The language of R3.1 does not reflect the intent described in the Rationale. Specifically, whether locations where busses are effectively tied together, such as on ring or breaker-and-half bus configurations, can derive the required phase-to-neutral voltages by monitoring a minimum of two of each Phase-to-Neutral voltages, from either line terminal or bus potentials. In a typical large switching station, this could eliminate costly retrofits to literally provide all three phase-neutral voltages for "each line or bus." o The language of R6.3 does not specify the method used to provide "Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required." If a single phase voltage and current are collected for R6, is it acceptable to calculate power flows expressed on a 3 phase basis derived from single phase quantities? Allowing calculated power flow would prevent costly retrofits to literally provide 6 dedicated analog traces for each Element required to have a DDR.R10: The "Rationale for R10" language, "Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset." Hence, requested records must be supplied in UTC format, but the collected and stored format do not. Similar to the "R3 and R6" comments above, the Requirement 10 and/or M10 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding.R10: Additionally, the "Rationale for R10" language should provide a caveat to allow for manipulating event records to UTC for equipment that is synchronized but cannot time-stamp with UTC as the reference. This would be similar to the "or derived" language suggestions to Requirements R3 and R6 which would allow for legacy equipment to meet the standard as well as allow for the time-alignment for multiple FR/SOERs as M11 evidence. Similar to

Organization	Question 3 Comment
	the "R3 and R6" comments above, the Requirement 10 and/or M10 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding.R11: (Requirement 11.4) If relays meet the requirement of a DDR, the language of R11.1 or M11 should specify that synchrophasor data is acceptable for DDR analysis. Relay Synchrophasor data is not compatible with the legacy COMTRADE format.R11: (Requirement 11.5) Additionally, add "Rationale for R11" language, "Collected and stored data does not need to follow the "C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME)" file naming format. The data provided pursuant to a data request must be provided in the C37.232 file naming format. Similar to the "R3 and R6" comments above, the Requirement 11.5 and/or M11 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding.
Response: The intent of a rationale box is to explain and clarify the intentions of the associated sections of the standard. After approval, the rationale boxes will be moved to the end of the standard, prior to the Guidelines and Technical Basis Section. The requirements of the standard are what will be audited; the rationale boxes are for an entity's or auditor's reference. The Standard Drafting Team reviewed the requirements and their associated rationale boxes to ensure consistency and completeness. **Requirement R2--PRC-002-2 addresses "what" data is recorded, not "how" it is recorded. Because of the significant differences between legacy DDR equipment and modern continuously recording DDR equipment it was necessary to address those differences in the standard.** **Requirements R1 and R5--The Implementation Plan specifies that: "Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list."** **Requirements R3 and R6--The wording in the rationale boxes for Requirements R3 and R6 was revised to clarify the intention of the requirements. Having adequate electrical quantities to calculate or derive other electrical quantities is the intent of these requirements.** **Requirement R10--The wording in the rationale box for Requirement R10 was revised for clarity. Data provided must be in the UTC format. The standard is addressing in what format the data must be provided.** **Requirement R11--Data must be provided in the formats specified to ensure uniformity to aid event analysis.**	
Liberty Electric Power, LLC	Generator owners should not be required to install DME. Generators do not model the BES, have no overall awareness of the state of the BES, and are not monitoring the overall state of the BES.

Organization	Question 3 Comment
	The requirement should be, at most, to provide a signal showing breaker position to the TO. Requirements for GOs to provide equipment are properly the realm of the interconnection agreement, not a NERC standard, and the SDT is intruding on the contractual relationship between REs.
Response: The standard deals with "what" data is captured, not "how" it is captured. It is not intended to require redundant data capture. The goal of the standard is that the data be captured. The SDT disagrees with any statement or implication that GOs should not be responsible for DDR data in PRC-002-2. Whether a GO has need or use for DDR data for its units does not impact the grid's need for it for event analysis – which benefits all users, owners and operators of the BES - after a system event. And it is consistent and logical practice in all NERC standards that owners of BES equipment are responsible to provide data required by that standard, for the BES equipment they own. Consequently GOs are correctly responsible in PRC-002-2 for the DDR data required from their units by the standard, not others such as TOs.	
Ingleside Cogeneration LP	ICLP has been closely following the distribution of the Cost Effectiveness Analysis Process (CEAP) survey and its results. We agree with the general findings that the existing base of Disturbance Recorders are mostly sufficient to meet PRC-002-2's locating and capability requirements - and that the reliability benefit of adding more equipment is minimal. However, it seems to us that NERC's and the Regional Entities' data analysis teams feel that the information provided in the evaluation of recent events is still lacking. This conflicts with the equipment owner's opinions and should be reconciled. Unfortunately, the only justification seems to be that the 2003 investigation recommended the action and FERC directed it be done. This is not a minor point. The benefits of reliability oversight at the national level may be the most difficult to assess, but are the most important. Every dollar spent on compliance needs to be properly allocated, otherwise it will go to less important initiatives. As such, ICLP urges that another CEAP survey be performed - but this time by the ERO community. Any perceived value should be quantifiable, so that it may be compared to the costs we all take on.
Response: Thank you for the comment. The CEAP process was performed and endorsed by the NERC Standards Committee for this standard. It is not meant to be a cost/benefit analysis. It is intended to be a cost-effectiveness analysis to provide stakeholders an	

Organization	Question 3 Comment
opportunity to provide potential costs associated with the standard, as well as potential alternative solutions that would meet the intent of the standard.	
MRO NERC Standards Review Forum	In both R3 and R4 it appears the applicability is for Transmission Owners and Generator Owners but the GO typically does not own a substation bus, transformer with a low-side of >100 kV, or transmission lines (as a registered entity of GO). We believe Generator Owner should be removed from these requirements. In R5 please consider the following modifications:R5.1.2, bullet 1 - Add "as judged by the Responsible Entities" to the end of the bullet.R5.1.2, bullet 5 - Add "as judged by the Responsible Entities" to the end of the bullet. R5.2.2 - Add "within the past 10 years" to the end of the requirement to provide a reasonable and finite time frame. The NSRF interprets R11.2 to say that NERC/Regions will always submit a request for data within 10 days of an event, so it is not necessary for DME's to hold data longer than that timeframe. As this impacts the memory/storage capability of the equipment we would appreciate clarification as to how the 10 days was determined and if the SDT believes the timeframe is long enough.
Response: The DMSDT disagrees with any statement or implication that GOs should not be responsible for DDR data in PRC-002-2. Whether a GO has need or use for DDR data for its units does not impact the grid's need for it for event analysis – which benefits all users owners and operators of the BES - after a system event. And it is consistent and logical practice in all NERC standards that owners of BES equipment are responsible to provide data required by that standard, for the BES equipment they own. Consequently GOs are correctly responsible in PRC-002-2 for the DDR data required from their units by the standard, not others such as TOs. **Regarding Requirement 5 Part R5.1.2, the bullets have been removed and the sub-part revised to: "Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL)."** **Requirement R5 Part R5.2.2: It is not necessary to be restrictive on the timeframe for the historical peak system Demand in Requirement R5 Part R5.2.2.**	

Organization	Question 3 Comment
Your interpretation is correct. Data will be requested soon after a major incident. The Drafting also considered available storage capabilities, and it judged 10 calendar days to be an appropriate timeframe.	
ITC	ITC feels that the Requirement 10 specification of + 2 milliseconds of Coordinated Universal Time (UTC) is too restrictive for a number of industry wide installed modern microprocessor based relays. These relays have proven to be reliable from a protection, SER, and FR perspective. Additionally, the present PRC-018 standard indicates that a DME's clock shall be synchronized within 2 ms. ITC agrees the PRC-018 synchronism requirement would be acceptable for SER device clocks but not data. It is recommend that the DMSDT consider changing the tolerance level for breaker status SER to be within 10 milliseconds. This would allow the continued use of these microprocessor based relays. This will be consistent with DMSDT guidance that microprocessor relays are acceptable implementations of SER and FR.
Response: Requirement R10 has been revised to relate to time synchronization of the device clock rather than data. All modern digital SERs have an internal clock accuracy of much tighter than what has been specified in the standard. **"R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 that meet the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]** **10.1 Synchronization to Coordinated Universal Time (UTC), time stamped with or without a local time offset.** **10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC."**	
Lincoln Electric System	Per Attachment 1, Step 1 utilities are instructed to "Determine a complete list of BES buses that it owns." A complete list of BES buses could include tap buses feeding radial load where there would be no BES circuit breakers or relaying and therefore no ability to gather the data pertinent to this standard. The SDT response to LES' previous comments stated that, "If a tapped substation was not modeled in a system study as a bus then it would not be considered a bus." If this is the drafting team's intent, it should be clearly stated in Step 1 that tap buses with no BES breakers or relaying are not to be included. Doing so eliminates any possible confusion associated with

Organization	Question 3 Comment
	whether a bus has been included in a system study. Whereas a Planning study model may not include these buses, a System Protection study model would in consideration that non-BES transformer relaying at the tap has to be coordinated with relaying at adjacent substations. R11.2 specifies "The recorded data will be retrievable for the period of 10 calendar days preceding a request." For clarity, LES suggests restating R11.2 as follows: "The recorded data will be retrievable for the period of 10 calendar days following the date that the data was recorded." Wording it this way ensures that the 10 calendar day timeframe starts on the day that the data was recorded. If left unchanged, the existing statement would tie the 10 day timeframe to the date of the request which makes the timeframe indefinite given the fact that the requesting entity has no time limit on when a request can be made.
Response: The DMSDT has revised the first sentence to: "For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid." The wording of Requirement R11 Part R11.2 was revised as suggested.	
PJM Interconnection	PJM urges the drafting team to reconsider including some type of alternative method for determination of the BES buses requiring sequence of events recording and fault recording as stated in the BES detailed methodology included in R1 and detailed in Attachment 1 of the standard. PJM suggested an alternative method that would be less burdensome for entities working on installation of or already have installed modern equipment with FR and SOER capabilities on their circuits. PJM appreciates the drafting team's consideration of our proposed alternative method and understands that it is not included in the draft standard presently posted. PJM feels strongly regarding inclusion of some type of alternative method and therefore will be submitting a negative ballot for the draft standard.
Response: The Standard Drafting Team evaluated methods of determining how to locate SER and FR data recording capability, and decided on Attachment 1 as being the best universally-applicable option. The DMSDT does not believe that the methodology is burdensome. The methodology only asks for BES buses rather than line terminals and only requires at least 20 percent coverage. This reduces the compliance burden for each entity.	

Organization	Question 3 Comment
Exelon Companies	R1: See comments to question 1. R2: It is not necessary to monitor circuit breaker auxiliary contacts to figure out when a circuit breaker opened or closed. Loss of current can be monitored in a fault recorder. This requirement puts a high burden on identifying print #s to show circuit breaker auxiliary contacts are connected to relays with SER capability. This effort is just not necessary based on our experience investigating thousands of operations over the years. The drafting team should eliminate this requirement or modify it to clearly state that cessation of current can be used to determine when circuit breakers open. R3: T-lines are exposed to a much higher number of faults/operations than T-transformers. Thus, modernization of T-line protection provides the greatest increase to reliability by a large margin. Having modern relays on T-lines allows for deducing current in transformers if necessary. The drafting team should concentrate on lines rather than transformers as the industry is doing. The drafting team should remove transformers from R3 since this information can be deduced from line monitoring or change R3.2.1 to state Transformers... “only when sufficient line monitoring is not present to derive transformer quantities”. R4: No comment, previous changes made by the drafting team addressed our concerns. R5: No comment, previous changes made by the drafting team addressed our concerns. R6, R7, R8: No comment. R9: The drafting team should eliminate requirement 9.1 unless they are aware of a significant portion of the industry installing equipment that doesn’t meet this requirement. To our knowledge, the main manufacturers of this equipment all easily exceed this requirement. R10: The drafting team should eliminate the requirement of within +/- 2 msec of UTC unless they are aware of a significant portion of the industry installing equipment that doesn’t meet this requirement. To our knowledge, the main manufacturers of this equipment all easily exceed this requirement. R11: No comment.

Organization	Question 3 Comment
	R12: We're using microprocessor relays for FR and SOE capability. They are tested under PRC-005 and alarmed upon failure. We should not have to keep track of every relay that fails on the system that we fix or replace for this standard. We have plenty of incentive to keep our relays working already and we don't run with failed relays for 90 days. Hence, there is no need for R12 and it should be eliminated. It is 100% burden, a complete waste of engineering resources, and hence a detriment to overall reliability. If the drafting team will not eliminate this requirement, it should be re-worded such that it is very clear that we do not need to keep track of failures that are rectified within 90 days. We should not have a compliance burden to prove that we fixed something in 2 days. An overall comment is that we believe this standard is not required for FR and SOE. These functions are built in to modern relays being adopted industry-wide already. All the requirements related to FR and SOE should be eliminated and the standard written to address DDR only. It is even arguable that this standard is required to promote DDR capability as the widespread use of synchrophasors including their storage has greatly expanded since 2003.
Response: R1: Please see responses to Question 1. **Requirement R2: Current through a breaker may be zero without a breaker opening. Breaker position status data is necessary for disturbance analysis. For multiple feeder tripout disturbances, circuit breaker SER data has been useful in making timely restoration decisions.** **Requirement R3: Requirement R3 states "...to determine..." As you intimate, an entity just has to be able to determine the quantities in the requirement.** **Requirement R9 Part R9.1: Even though 960 samples per second is common in industry, Requirement R9 Part R9.1 was included to ensure adequate accuracy for calculations.** **Requirement R10: Even though +/- 2 miliseconds is common in industry, Requirement R10 was included to ensure adequate accuracy for calculations. R10 was also revised to provide clarity:**	

Organization	Question 3 Comment
“R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 that meet the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 10.1 Synchronization to Coordinated Universal Time (UTC), time stamped with or without a local time offset. 10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.” R12: If you have compliance data for PRC-005 that meets the requirements in Requirement R12, then you can use the same data for compliance with PRC-002, Requirement R12. Requirement R12 stipulates that for a failure of recording capability an entity has ninety 90 calendar days to get it restored, or file a Corrective Action Plan. SCADA logs could also be used as evidence and this has been added to the measure. PRC-002-2 ensures that there will be "...adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances." This includes FR and SER data as they are critical items that assist in determining what happened during a disturbance.	
ReliabilityFirst	ReliabilityFirst has the following comments for consideration: 1. Requirement R6, Part 6.1.3.2 - For Requirement R6, Part 6.1.3.2 if plant that has six 200 MVA units, does this plant require any DDRs? As currently written, ReliabilityFirst believes no DDRs are required at this facility. From a monitoring perspective, ReliabilityFirst believes any plant/facility that has an aggregate nameplate greater than 1000 MVA, should have equipment capable of DDR. 2. Requirement R12, Part 6.1.3.2 - ReliabilityFirst does not understand the reasoning behind requiring the submission of the timeline for restoration and a Corrective Action Plan (CAP) to the Regional Entity. Without a requirement for the applicable entity to “implement” the CAP, the Regional Entities will have little recourse and there is little value in having the CAP if there is no requirement to complete it. Theoretically, the CAP could go on in perpetuity without completion and the entity would still be compliant, but the problem would remain unresolved. Furthermore, if the requirement requiring the applicable entity to “implement” the CAP, the Regional Entities can monitor implementation through a Regional Entity monitoring method. ReliabilityFirst recommends removing the “for submission to the Regional Entity” language and include

Organization	Question 3 Comment
	implementation language as follows:i. "...restore the recording capability or develop a timeline with milestones for completion for restoration and implement a Corrective Action Plan (CAP)." 3. VSL for Requirement R2 - ReliabilityFirst believes the gradation of VSLs should be in 10% increments (or similar to the VSL designations for Requirement R1). As written, if an entity only had 51% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers they would only fall under the moderate VSL. ReliabilityFirst believes missing close to half of the total SER data is completely missing the intent of the requirement and should be designated as a "Severe" VSL. ReliabilityFirst has a similar comment for the VSLs associated with requirements R3, R4, R6, R7, R8 and R9.

Response:

1. The reference is to Requirement R5 Part R5.1.1. A plant with six 200MVA machines would not be required to have DDR. The Standard Drafting Team intended to establish generating resource monitoring requirements to develop a foundation for which data is required to be captured.

2. Referring to Requirement R12, the Standard Drafting Team decided to have the CAP submitted to the Regional Entity because of its overview of the system. Corrective Action Plan is defined in the NERC Glossary of Terms as:

A list of actions and an associated timetable for implementation to remedy a specific problem.

The CAP therefore, would include a timeline for restoration. The Drafting Team did not want to get more specific on milestones for restoration of the capability because from experience it is unrealistic to place milestones on returning the capability to service because of uncertainties in supply and delivery of what is needed to make restoration. The Drafting Team revised the wording in the requirement and Rationale Box. The Regional Entity would determine if the timetable was acceptable.

R12. Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

- **Restore the recording capability, or**
- **Submit a Corrective Action Plan (CAP), to the Regional Entity and implement it.**

3. The DMSDT concurs and has made the revisions as suggested.

Organization	Question 3 Comment
Seattle City Light	Seattle appreciates the efforts of the Drafting Team to respond to comments received following the initial posting of this draft Standard. However, Seattle fundamentally disagrees with the approach proposed by draft PRC-002 for several reasons. 1. First, the proposed Standard requires an entity to establish at least 43 new controls to meet the compliance assessment approaches identified in the draft RSAW, and this figure does not consider the dozen or additional controls required to ensure all Attachment 1 steps are met. For context, consider that approximately 4-5000 controls are required to meet the entire body of NERC Standards. As such proposed PRC-002 represents a 1% increase in the overall compliance burden on the electricity enterprise. Entities will be required to monitor performance of minor activities, and auditors likewise will be required to examine performance. Seattle does not believe the reliability benefit offered by this Standard warrants this new compliance burden. Indeed each requirement of PRC-002 is identified as “Lower” for violation risk factor (the lowest rating possible), indicating that the drafting team does not consider any requirement of the Standard to have a critical impact on BES reliability. Rather this Standard supports long-term operational improvements in the BES. Seattle believes such improvements are important and supports a reasonable approach to disturbance monitoring, but does not support the complex, over-engineered Standard. 2. The bus screening process is an example of a process that needs to be simplified. The rational does not seem to be well thought out and is certainly not easy to explain and implement (worse than the FERC Order 754 exercise that industry recently participated in). The attached Excel spreadsheet and the directions for completing it are very cumbersome and inefficient--a lot like trying to fill-out a Federal Tax form. Instead of giving an entity the metrics to be achieved, this approach attempts to create a cookbook format where data needs to be entered in one part of the spreadsheet, and then subtracted out in another part of the spreadsheet. 3. Seattle believe appropriate and reasonable a general requirement to have disturbance monitoring, but believes the technical requirements for data type, frequency of sampling, and so forth would be better handled in a criteria or guideline document. Once such requirements are codified as federal law it is cumbersome and lengthy process to change them, yet all are aware how fast technical change has occurred in the area of disturbance monitoring. Moving

Organization	Question 3 Comment
	the technical requirements from the Standard to a guidance document likewise would significantly reduce the compliance burden associated with the draft. 4. Finally, Seattle requests technical justification by established for continent-wide application of a 1500 fault MVA threshold. Once established in a Standard, a technical justification will be required for any change; as such technical justification should be provided beforehand to establish the value as correct and appropriate. This value may be correct and appropriate for the NPCC area, but has not been justified in other regions. It may well be correct and appropriate, but a justification has not yet been provided.

Response:

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

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

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

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

The Lower Violation Risk Factor was selected for the PRC-002-2 requirements because they do immediately affect the real-time electrical state or capability of the bulk electric system.

2. The bus identification process provides a consistent method to be able to define for what BES Elements data needs to be captured.

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

Organization	Question 3 Comment
4. The 1500 MVA value was arrived at based on three phase fault MVA data collected from industry from the June 5, 2013 Informal Request for Information posting.	
PPL NERC Registered Affiliates	See comments 3a-3c below. 3a. The Guidelines and Technical Basis Section of the standard states in the first paragraph on p.33 that, "SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data." The next section (Guideline for Requirement R2) states however that "Generator Owners are included in this requirement [for SER data] because a Generator Owner may, in some instances, own breakers connected to the Transmission Owner's bus." All generator output breakers connect eventually to the transmission system however, nor is it clear why the aforementioned lack of tripping time reliability for GO sequence-of-events monitoring would apparently apply in some cases (GO SER data mandatory) and not in others (GO SER data not required). 3b. The Guideline for Requirement R3 on p.33 states that "Generator step up transformers (GSU) are excluded from the above based on the following:- Current contribution from a generator in case of fault on the transmission system will be captured by FR data on the transmission system.- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed. The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data." This seems to fully exclude GOs from fault recording obligations, so why are GOs obligated in R3 and R4 to have FR data? 3c. Comments 3a and 3b above gain emphasis from the circumstance that it is expected that the Guidelines and technical Basis Section of the draft standard will be deleted if and when PRC-002-2 is voted-in and approved by FERC. That is, the logic by which GOs are sometimes in and sometimes out will be even more obscure than it is now.

Organization	Question 3 Comment
	3d. The requirements for GOs to "have" SER (R2), FR (R3 and R4) and DDR (R7) data are understood to mean that they do not need to own this equipment, and it would do just as well to have an agreement with the TO to fulfill the PRC-002-2 requirements if and where the TO already has DME on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002-2. There should be a footnote saying that "This standard defines the 'what' of DDR, not the 'how.' GOs may install DME or, where the TO already has suitable DDR, contract with the TO." It would be still better to just drop GOs from the picture, however, per our comments above.
Response: **3a. While DDR data more accurately reveals how a generator is behaving, SER data for breakers connected to a transmission system bus is useful in determining fault clearing times, and identifying interrupting device problems. The intent is to have SER data for generator output breakers connected directly to a Transmission Owner's Bus. SER and FR data is needed to analyze "fast" disturbances on the BES, not the slowly evolving disturbances captured effectively by DDR. The wording of the Guideline for Requirement R2 was revised.** **3b. Requirements R3 and R4 apply to GOs to ensure that data is collected for transmission system BES Elements a GO might own.** **3c. The Guidelines and Technical Basis Section stays with the materials for the standard after the standard is approved by FERC. The Standard Drafting Team is revising the Guidelines and Technical Basis Section to ensure consistency.** **3d. As stated, the standard does not deal with "how" data is recorded, but "what" data is recorded. Because of the importance of generator response to system disturbances, the GO is needed to be included in this standard. A statement has been added to the Introduction of the Guidelines and Technical Basis Section to reinforce the "what" versus "how."**	
SPP Standards Review Group	Some drafting teams have adopted a convention of hyphenating terms such as 30-, 60- and 90-calendar days. We suggest the DM SDT do the same. Similarly, '30-cycle post-trigger' should also be hyphenated. We also noted that in the redline, step-up transformer was hyphenated in some places and not others. However, in the clean copy of the standard it is not hyphenated. We believe it should be. In some places in the documentation three-phase is hyphenated and in others it is not. While we think it should be, we encourage the DM SDT to be consistent. 'Disturbance' is defined in the NERC Glossary and depending upon its usage should be capitalized. The DM SDT needs to be

Organization	Question 3 Comment
	consistent with its format. In the 2nd line of M3, insert 'that' in between 'data' and 'is'. In the 3rd line of the 1st paragraph in the Rationale Box for R5, it would be appropriate to use BES rather than spelling out Bulk Electric System. Add a hyphen to 'high-' in the 3rd line of the Rationale Box for R7. This is consistent with usage throughout the rest of the documentation. We suggest modifying the first sentence of Requirement R8 such that it reads: 'Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage.' There are a couple of instances in the 3rd paragraph of the Rationale box for R11 where 10 days is used. We believe this should be 10-calendar days. Also, in the next to last line of the last paragraph 'disturbance recording' is capitalized. It is not a defined term in the NERC Glossary and shouldn't be capitalized. This change needs to be made throughout the documentation. In the 6th line of the Rationale Box for R12, 'entity' should not be capitalized. In the VSLs for R2, insert 'Owner' between 'Transmission' and 'or' for consistency throughout the VSLs for the other requirements. We suggest the following replacement for the 2nd item under Step 7 of Attachment 1. 'If the list has 1 to 11 BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3. Proceed to Step 9.''Disturbance monitoring' is capitalized in the Introduction of the Guidelines and Technical Basis Section. Since it is not a defined term in the NERC Glossary, it shouldn't be capitalized. Modify the next to last line of the 1st paragraph in the Guideline for Requirement R1 to read '...voltage and current for individual circuits allow precise reconstruction of events of both...' Change 'disturbance' to 'disturbances' in the next to last line of the 2nd paragraph. In Item 6 on Page 32 (clean version) of the same section, insert 'to those' between 'buses' and 'with'. In the 6th bullet under Item 8 on the same page, change 'Owners'' to 'Owner's'. Hyphenate 'in-effect' in the 1st line of the 2nd paragraph of the Guideline for Requirement R3. Modify the 1st line of the Voltage Recordings section on Page 34 (clean version) to read 'Voltages are to be recorded at applicable BES buses. Note that Requirement R3 calls for the...'Delete the 's' on 'meets' in the 2nd line of the 1st paragraph of the Guideline for Requirement R4. Change 'captured' in the 1st line on Page 35 to 'captures'. In the 2nd line of the same paragraph, set the phrase 'when time synchronized to a common clock' off with commas. Delete the last sentence of the 1st full paragraph on Page 36 (clean version). It is a duplicate. Insert an 'a' between 'after' and 'fault' in the 1st line of the 1st paragraph under Guideline for Requirement R6.Replace 'has' with

Organization	Question 3 Comment
	'with' in the 3rd line of the 1st full paragraph on Page 37 (clean version). Near the end of that same line, there appears to be an extra space between 'Bus,' and 'would'. Skip a line and hyphenate 'in-service'. Capitalize Real Power and Reactive Power here and in the last paragraph before Guideline for Requirement R7. Add a hyphen to 'high-' at the end of the 1st line under Guideline for Requirement R7.Hyphenate 'short-term' in the 2nd line of the 1st paragraph under Guideline for Requirement R9. In the 4th line of the 2nd paragraph, insert an 'a' between 'in' and 'sampled'. Capitalize 'Requirement R1' and 'Requirement R5' in the 3rd line of the 1st paragraph under Guideline for Requirement R11. Delete the 'a' in front of 'Day 1' in the 6th line of the 3rd paragraph under Guideline for Requirement R11. Insert an 'and' and delete the 'it' in the 2nd and 3rd lines of the 2nd paragraph on Page 40 (clean version). That portion of the sentence should then read '...Transient Data Exchange and is well established in the industry.' Split the 2nd sentence of the 3rd paragraph on Page 40 (clean version) into two sentences such that it reads '...Naming Time Sequence Data Files. The first version was approved in 2007.' In the 4th line of the 3rd paragraph on Page 40 (clean version) replace 'was' with 'were'. Hyphenate 'out-of-service' in the paragraph under Guideline for Requirement R12. Also, there appears to be an extra space between 'develop' and 'a' in the 10th line of the same paragraph.
Response: The wording and punctuation in the standard has been reviewed, revised, and made consistent. Terms using "calendar date" have been hyphenated throughout as well as step-up and 30-cycle post-trigger. The DMSDT capitalized Disturbance as well as System and Transmission throughout the standard where appropriate. The other grammar and syntax changes that you suggested were incorporated into the standard.	
PNM	Suggested rewording of R12 to clearly state submission of CAP is required. "...develop a timeline for restoration and submit a Corrective Action Plan (CAP) to Regional Entity."
Response: The wording of Requirement R12 was revised to specify submittal of a CAP as well as implementation of the CAP.	
Tacoma Power	Tacoma Power disagrees with the need for this standard and believes there are more cost effective alternatives for acquiring the data necessary for event analysis. However, assuming that this standard will likely proceed to approval, we are providing both comments for improving the draft

Organization	Question 3 Comment
	standard and an explanation for why we believe this standard is not the appropriate method to address the perceived needs. a. Under Measurement M3, change “...of FR data is...” to “...of FR data that is...” b. Under Measurement M11, change “...evidence (electronic or hard copy) data...” to “...evidence (electronic or hard copy) that data...” c. What if FR, SER, or DDR equipment is taken out of service for maintenance and/or testing. Could this result in an automatic violation of Requirement R11, Part 11.2? Or, should this be treated like a failure under Requirement R12? d. In Attachment 1, Step 7, for cases in which the list has 11 or fewer BES buses, change “...at the BES buses with...” to “...at the BES bus with...” e. Please confirm that only the channels that trigger need to be provided upon request and that no cross-triggering between FR or SER is required. f. Requirements R3 and R4 should require the capability to record data rather than requiring data. g. The VSLs for Requirement R10 should be based on the number of missed electrical quantities rather than the number of BES buses. Otherwise, please provide guidance on how a substation with several relays correctly time stamped but one relay with an incorrect time stamp should be treated. h. Requirement R10 should be modified to have SER timestamping to +/- 40 milliseconds while maintaining the FR and DDR timestamp of +/- 2 milliseconds for two reasons. First, the breaker position indication using 52a or 52b contacts can be different than the main contacts opening and ultimate current interruption by more than 2 cycles. Typical, 52a vs 52b contacts are at least Â½ of a cycle apart. Timestamping the relay input to 2 milliseconds will not actually indicate the state of the power system. Second, SEL 300 series relays timestamp SERs to the nearest quarter cycle, so a large number of installed relays would not meet the requirements for SERs. These relays do timestamp the FR to the specified accuracy, just not the SER.Alteratives to this draft standard:The 2003 outage report outlined major deficiencies with event recording, but the data recording technology has dramatically changed in the last decade. Even though no standard was in place

Organization	Question 3 Comment
	specifying data recording, utilities have been installing GPS time stamped event recording based on business drivers. As outlined during the CEAP report, the labor for event report alignment was reduced from 4,400 person-hours for the 2003 outage to only a week for the 2011 southwest outage. Although further reductions in event analysis SME hours would result from this standard, the compliance SME hours would dramatically increase and result in overall higher costs. As outlined in the CEAP report, most utilities already have event recording in place, or are going toward recording as part of multifunctional equipment installations. Therefore, ignoring automated event collection, the only costs that should be considered are due to the increment burdens of documenting compliance with this standard. Instead of this standard, we believe that a NERC guidance document on event reporting best practice would be equally effective while requiring very little compliance burden. In other areas, NERC is moving away from standards that require zero defects in high volume tasks. This standard requires 100% accurate time stamping of 100% of a small portion of elements, but then ignores 80% of BES buses. On a voluntary basis, we have approximately 50% of elements monitored. Thus if we supplied only the event reports required by the standard, the coverage of our system would go down dramatically. In order to meet the zero defect policy of this standard, we will have to redirect efforts from actual event analysis to documentation of event recording capability. If data recording is implemented as a standard instead of a best practice guideline, it sets the minimum bar instead of the optimal goal. Most utilities already have at least a marginal level of recording capabilities. We would prefer NERC to aim higher. The best event records occur when all data channels at a substation are recorded for a trigger on any channel for any kind of transient, including frequency or overvoltage. This level of recording is impractical to require as a standard but is already in place for many utilities. For an enforceable standard, we agree that undervoltage & current are the only reasonable triggers to require.We are concerned that the SDT appears to have based installation cost assumptions on the premise of using data stored locally on relays. If this is an enforceable standard with a zero defect requirement, utilities are in essence forced to automated event collection from relays in order to guarantee zero defects. This automated event collection then brings in large costs for communications, and for applying CIP standards to those communications. If this were a best practices document, or allowed some data gaps, local relay storage would be a reasonable assumption.

Organization	Question 3 Comment
Response: **a. The wording of Measure M3 has been revised.** **b. The wording of Measure M11 has been revised.** **c. The Rationale Box and Guideline for Requirement R12 explain that any recording capability outage greater than 90 calendar days is treated as a failure of recording capability.** **d. The wording in Attachment 1, Step 7 has been revised.** **e. The triggered channel data will be requested after a system disturbance. The appropriate triggering implemented to capture the desired data is the intent of PRC-002-2.** **f. The standard is about "what" data is recorded, not "how" it is recorded.** **g. The VSLs correctly reflect the necessities for correctly collecting data. The time stamp associated with the data collected for a BES Element must be correct.** **h. PRC-002-2 is about "what" data is recorded, not "how" the data is recorded. Requirement R10 was revised to address synchronization to Coordinated Universal Time, and synchronized device clock accuracy to +/- 2msec to reflect equipment realities. It is understood that there are many entities that have the capabilities called for in the standard in place already, but the intent of the standard is to ensure there are no gaps. Having recording capability beyond what is required in the standard is an engineering, planning, and operational plus. It is difficult, if not impossible, to quantify the costs of implementing lessons learned from events analysis made possible by the availability of system data.**	
~~City of Tallahassee~~	~~TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.~~
~~City of Tallahassee~~	~~TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.~~

Organization	Question 3 Comment
City of Tallahassee	TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.
Response: The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report: **"Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed.** **A valuable lesson from the August 14 blackout is the importance of having time-synchronized system data recorders. NERC investigators labored over thousands of data items to synchronize the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly improved and sped up if there had been a sufficient number of synchronized data recording devices."** **The Disturbance monitoring recordings can be used to improve reliability by providing information that can guide operators in better real-time system management (real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events.** **Event analysis allows industry to take steps to prevent recurrence of an incident. This standard will ensure that there are no gaps in the data, and sufficient and complete data is available for this analysis. DDR is especially useful in analyzing generator performance and response. It is difficult, if not impossible, to quantify the costs of implementing lessons learned from events analysis made possible by the availability of system data.**	
Colorado Springs Utilities	Thank you SDT for your efforts we voted negative for the following reasons:This standard brings 20% of our buses into scope, which means it will bring 20% of just about everyone's buses into scope (some large companies could have hundreds of buses included). Is that really the SDT's intent? It sounded like the SDT is not expecting it to be that big of an impact. The MVA threshold needs to be re-visited to prevent excessive, unmerited impact. We do not believe that it is logical to include a bunch of buses from smaller entities that just barely cross the threshold and then only include the top 20% of companies with buses having orders of magnitude greater short circuit duty. How can the inclusion criteria be modified to make sure that we capture the appropriate points of the system based on actual risk and impact to the BES? The current criteria is too inclusive and too

Organization	Question 3 Comment
	generic - which impacts industry unnecessarily without getting the desired result.Thank You!Bottom line, IMO, the technical basis for this standard is flawed.
Response: After a review of the data received from the June 5, 2013 Request for Information, the Drafting Team decided upon the numbers used in the standard, and that the implementation of the standard to those identified BES buses and BES Elements would provide adequate system Disturbance Monitoring. The recording capabilities would provide adequate data to reconstruct a major system incident, and allow an analysis that could prevent a future recurrence. Note that the standard allows an entity to determine quantities.	
JEA	The 1500MVA threshold is too low and needs to be increased.
Response: The Standard Drafting Team is made up of members from different size entities, and received input from the June 5, 2013 Request for Information posting from across the continent to determine the numbers and philosophies used in Attachment 1.	
SERC Protection and Controls Subcommitee	The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: Thank you for your comments.	
Northeast Utilities	The preparation and accuracy of the redlined version and this unofficial comment form is lacking and promotes confusion. The redlined version does not effectively show many of the numerous redlined changes from the last posting, including nearly all of R5. The comment form description of the changes to the implementation plan does not agree with the standard. From above description of changes:"The schedule for implementation is now to be at least 50% compliant within three (3) years following notification of the list, and 100% compliant within five (5) years following notification of the list. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be 100% compliant within five (5) years following notification of the list."From the actual standard posted for comment:Entities shall be at least 50% compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective

Organization	Question 3 Comment
	Date. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be fully compliant within four (4) years of the Effective Date. Page 11, Requirement 5 states “Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder recording (DDR) data is required, ...”While page 5 (blue explanation box& Mapping document) still states “Rationale for Functional Entities: The Responsible Entity - the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection - has the best wide-area view of the BES and is most suited to be responsible for determining the Elements for which dynamic disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected.
Response: There were problems encountered in finalizing the clean and redlined versions of PRC-002-2 and its Implementation Plan for the posting. Regarding the implementation for requirements R2-R4, R6-R11, **"Entities shall be at least 50 percent compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date.** **Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the Effective Date.** **Entities shall be 100 percent compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list."** **Because DDR is useful for analyzing slowly evolving widespread system disturbances, the Responsible Entity (PC or RC), is in the best position to determine from where DDR data should be captured.** **The standard and its Rationale Boxes and Guidelines have been reviewed for consistency and revised accordingly.**	
Seminole Electric Cooperative, Inc.	The three-phase short circuit level minimum of 1500 MVA at BES voltage levels is low. As a result, entities must sort through large numbers of buses when only the top 11 would need to be selected. Buses at low three-phase fault current are not typically conducive to disturbance monitoring equipment. For example, a 345 kV bus that carries 3000 amps (normal flow) would be a candidate for PRC-002 even without applying a three-phase fault. It would seem that a threshold of 10,000 MVA is technically justifiable, since most BES stations that have over 10,000 MVA of available

Organization	Question 3 Comment
	three-phase fault current are candidates for being critical facilities that would benefit from disturbance monitoring equipment or already have such equipment installed. This would also reduce the number of buses that the TO needs to review.There is uncertainty regarding the technical justification for the "11" BES buses that is listed in Step 3 of Attachment 1. Requirement R8 does not clearly identify the data storage requirements for DDR with continuous recording capability. A 3-year period of continuous recording data per DDR location is too onerous. DDR continuous recording capability should be a minimum of 10 days per site. DDR recording(s) retained as evidence should strictly be limited to event-triggered recording by a system disturbance and where the RC, RE, or NERC requests data for the event within the 10-day time frame.Requirement R11.4's required conformance with IEEE Standard C37.111-"2013" is too onerous. This Requirement disqualifies the majority of FR and DDR equipment presently deployed. Seminole recommends revising the Requirement to require the use of IEEE Standard C37.111-"1999" or later.
Response: The Drafting Team is made up of members from different size entities, and received input from across the continent to determine the numbers and philosophies used in Attachment 1. The numbers chosen were the most appropriate to use after reviewing the data on hand from the June 5, 2013 Request for Information. Eleven were chosen as the number of buses specified in Step 3 of Attachment 1 after review of the data received from the June 5, 2013 Request for Information from industry, and the judgment of the Drafting Team from Real-time experiences. **The intent of the retention period is for the entity to retain the data that has been requested for a triggered disturbance only.** **Requirement 11 Part R11.2 has been revised.** **Requirement 11 Part R11.4 was revised to read C37.111-1999.**	
Pepco Holdings Inc.	Under requirement R11.2, suggest modifying the wording to the following: The recorded data will be retained for a minimum of 10 calendar days.
Response: Requirement 11 Part R11.2 has been revised to clarify that data retention is for a disturbance.	

Organization	Question 3 Comment
City Utilities of Springfield, MO	We continue to believe the Attachment 1 fault MVA threshold established in R1 to identify potential buses from which to pick locations for FR (and SER) data is too low. To provide a context for our comment, our system has a peak load of 800 MW serving approximately 110,000 customers in a service territory covering 320 square miles (less than one county) with local generating capacity of 1100 MW. This is a very compact system containing a relatively small geographic footprint with 17 BES buses as defined within this draft standard. All of these 17 BES buses have fault MVA above the 1500 MVA threshold, ranging from 8,000 MVA down to 2,900 MVA with a median value (bus 6 out of the top 11) of 5,800 MVA. The top 10 BES buses on our system all have a fault MVA above 5,000. This PRC-002-2 draft Standard will require us to have FR data for 4 buses (20%) overall. The top 2 BES buses (10%) where FR data would be required will be electrically less than 2 miles apart. The other 2 buses (additional 10%) would be located 25 miles or less electrically from the first 2 buses regardless of how we elected to determine these locations. All this data will be electrically concentrated in a small geographical area, which doesn’t appear to lead to a wide-area view of the overall BES. Additionally, several of the above mentioned buses have only two (2) BES sources (Distribution buses with only 2 transmission lines connected) or tapped buses with Distribution transformer(s) and no transmission breakers. Are these buses really important to the BES in the context of DME data? It seems the PRC-002-2 R1 Attachment 1 method only serves to unnecessarily inflate the number of BES buses on which the overall percentage of required locations will be calculated. We recognize the difficulty the SDT had in determining the appropriate coverage for FR data, but contend that a fault MVA threshold closer to 4500 MVA and an overall coverage percentage of 10% is adequate. This would still result in our system having FR data at 2 buses which could be electrically separated by approximately 25 miles. Additionally, we believe buses with only limited sources from the BES should be excluded out-of-hand by some other “test” mechanism within the Attachment 1 document or some other vehicle. Regarding R3: 1) Is it the intent of the Standard that FR data is to be determined for all currents defined on all Elements connected to a selected bus for any single fault on any Element connected to the bus? (i.e. if using digital relays for FR, do relays on each element (line or transformer) need to trigger for faults on any element connected to that bus?)

Organization	Question 3 Comment
	2) What are the expectations for faults and/or disturbances located remotely from the selected bus - how sensitive are they expected to be? In reality, are these FR devices expected to be a lower level disturbance recorder? 3) If data is expected to be available for conditions other than just faults, the data should not be classified as Fault Recording data or at least further definition/clarification should be provided. 4) Some of the discussion in the rationale box for R3 seems to suggest the FR data be used for fault analysis, as it applies to determining correct and incorrect breaker operations - Misoperation determination. In the case of installed modern microprocessor relays, the protective relay(s) should be able to determine the nature of the fault, the elements that operated, fault location, voltages and currents and many other particulars associated with a fault. Generally, FR is an unnecessary addition of equipment in these situations from the perspective of fault analysis to determine the correctness of protection system operation. 5) Regarding R4: We propose changing the 30 cycle post trigger record length in the first bullet under R4.1 to a total record length of 30 cycles. The current wording requires a 32 cycle minimum total record length. We believe the 30 cycle total record length better matches existing microprocessor relay functionality for those that may wish to employ them in this fashion.
Response: The Standard Drafting Team is made up of members from different size entities, and received input from across the continent to determine the numbers and philosophies used in Attachment 1. The numbers chosen were the most appropriate to use after reviewing the data on hand. The Standard Drafting Team recognized that load dense areas' data may be required from stations that are only blocks apart. Note that the Requirements say to be able to determine--if data can be determined for an Element, the data does not have to be captured for that Element. To clarify what buses need consideration, From Attachment 1, Step 1: "For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus." 1. Requirement R3 stipulates that data is to be captured for "... each of the BES Elements it owns connected to the BES buses identified in Requirement R..." Sensitivity of the triggering for data capture depends on the parameters of the BES.	

Organization	Question 3 Comment
2. Data has to be captured for the identified BES Elements. Again, the sensitivity of the triggering depends on engineering judgment and the parameters of the BES. The standard is about "what" data is recorded, not "how" it is recorded. FR data conveys information different from DDR data, and is not intended to replace DDR data. **3. DDR would capture "slowly" evolving system conditions and disturbances that might not involve faults.** **4. FR data has been used successfully in rapid system restorations following multiple feeder tripouts to help expeditiously determine the faulted Element, and thus allow restoration of unfaulted facilities. The data provided by microprocessor relays may be used to satisfy Requirement R3.** **5. The Standard Drafting Team has revised the total record length to 30 cycles as suggested.**	
Kansas City Power & Light	We suggest that the DMSDT further clarify the Applicability of the Functional Entities in 4.1 by including a statement in the Rationale Box for Functional Entities that when Responsible Entity is used in PRC-002-2, it specifically refers to those entities listed under 4.1. This is a slightly different approach than usually taken in Applicability. Some drafting teams have adopted a convention of hyphenating terms such as 30-, 60- and 90-calendar days. We suggest the DMSDT do the same. Similarly, '30-cycle post-trigger' should also be hyphenated. We also noted that in the redline, step-up transformer was hyphenated in some places and not others. However, in the clean copy of the standard it is not hyphenated. We believe it should be. We suggest modifying the first sentence of Requirement R8 such that it reads: 'Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage.' There are a couple of instances in the 3rd paragraph of the Rationale box for R11 where 10 days is used. We believe this should be 10-calendar days. We suggest the following replacement for the 2nd item under Step 7 of Attachment 1. 'If the list has 1 to 11 BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.'

Organization	Question 3 Comment
Response: The rationale box for functional entities was revised to clarify the meaning of the use of Responsible Entity in PRC-002-2. **The text was reviewed and revised to ensure consistency in the use of hyphenation, punctuation and grammar.** **The wording in Requirement R8 was revised.** **The wording in the rationale box for Requirement R11 was revised.** **The wording for Attachment 1, Step 7 was revised.**	
Idaho Power Co.	When a relay is used to capture FR data rather than a digital fault recorder, Requirement R4.1 would necessitate a relay record length of at least 32 cycles under R4.1-bullet 1 or multiple triggers under R4.1-bullet 2. Our wide variety of relay types support records of 15, 30, 60, or 180 cycles. Current practice and preference is to use a record length of 30 cycles, trigger inclusive, which was chosen to balance the amount of information in a single record while still providing the capability in the relay to save multiple records. The 32 cycle requirement would force the use of 60 cycle event records. While many of our relays are capable of this, the practice may lead to missed event records impacting our ability to search for misoperations under PRC-004.Multiple triggering has already caused events to be missed in our system due to the limited capability of some legacy relays. A change to a record length of 30 cycles including the 2 cycles of pre-fault trigger would fit within our current practice which mitigates our capture problems.
Response: The Standard Drafting Team discussed changing the overall record length of 32 cycles. It is commonly employed in industry, and is not an unreasonable specification nor difficult to implement.	
Florida Municipal Power Agency	While FMPA appreciates the efforts of the SDT to address many of the specific comments received, FMPA's position remains that a standard is not justified for Disturbance Monitoring. We believe that Disturbance Monitoring is better addressed through guidelines than through a standard. The system has changed a lot over the last 10 years since the Northeast Blackout of 2003 and we can gain much more information now from microprocessor based relays and phasor measurement units (PMUs) prevalent throughout the system. The justification for this standard is primarily based on the decade old Blackout Report and does not take into account the changes in system

Organization	Question 3 Comment
	equipment since then. This justification was highlighted by the SDT's response to FMPA's prior comment about a standard not needed. SDT Response: "(1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:..."Additionally, it should be noted that in the Executive Summary of the Cost Effectiveness Analysis Process (CEAP) Pilot for this project, the following statement was made: "The majority of CEA respondents believed the standard's potential immediate reliability benefits were minimal." So, with this CEAP observation along with the low approval rating of 43.29%, there is clearly some significant stakeholder concern with the justification for this standard.In light of the Paragraph 81 Project, the industry is supporting reducing and consolidating the amount of requirements. This standard meets several Paragraph 81 Criteria used to identify requirements for retirement including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. There are 12 requirements and over 20 sub-requirements in the current PRC002-2 draft. The amount of detail is unnecessary and poses a serious compliance burden on registered entities. While we do not believe the standard is needed, we strongly recommend that if this project goes forward, that the drafting team revise this standard to two or three requirements. We point out that the NERC Rules of Procedure have a detailed section on Disturbance Response Procedures - Appendix 8.While we recognize that the SDT has limited latitude in eliminating a project or veering from the SAR, we suggest that the Standard Committee revisit the justification for this standard and at a minimum review the scope and prescriptiveness of the detailed requirements in light of the Paragraph 81 guidelines.

Response: The Standard Drafting Team realizes that improvements have been made to Disturbance Monitoring technology since the 2003 Northeast Blackout. That does not guarantee universal implementation, thus necessitating the need for the standard.

PRC-002-2 addresses "what" data is recorded, not "how" the data is recorded. This approach eliminates the complications that might arise from the technological advances being made to record the data.

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

Organization	Question 3 Comment
Xcel Energy	Xcel Energy engineers have conducted a test application of the selection criteria in Attachment 1, and have concerns that some locations are identified but provide little or no value (e.g. situations where fault recording is required for busses at both ends of a short line and one of the busses has only two sources (see diagram provided separately via email to the NERC SDT Coordinator for this standard)). We recommended an 'exception' written into the requirements with the Responsible Entity (or RC or Regional Entity) concurrence. In R5 - please clarify if the IROLs are those established by the TP, PC, or RC. (Also note that RC established IROLs may be in the operating horizon with little or no time for entities to actually install equipment).R12 should be reworded to state "...or develop and submit to the Regional Entity..." and end after "...(CAP)." R12 - is it inferred that entities can conduct maintenance on these devices (ie - out of service) as long as they meet the 90 day requirement? If so, consider making that clear.
Response: In developing Attachment 1, the Standard Drafting Team recognized that electrically close bus locations (referring to the diagram provided by Xcel Energy) would possibly diminish the overall "needed" number of locations to capture adequate SER and FR data for because of the possible concentration of load. The Standard Drafting Team considered this, and is addressed in Steps 7 and 8 of Attachment 1. **Because Requirement R5 pertains to the Responsible Entity (as used in the standard), the Responsible Entity is responsible for establishing the IROLs.** **The wording of Requirement R12 and its rationale box have been revised. Entities can conduct maintenance as long as the 90 calendar day requirement is met. That is also explained in the Guideline for Requirement R12.**	

ADDITIONAL COMMENTS:

Calpine Corporation
Hamid Zakery

. I had trouble with submitting comments. We appreciated the hard work demonstrated by the SDT and NERC members with this draft standard. I voted no for the following reasons:

1. Requirement R1 of the draft standard states each "Transmission owners shall identify BES buses for which SER and FR data is required....". Do elements connected to these bused include generators? We believe examples by illustration can provide much needed clarity.

Response: BES Elements connected to the identified BES buses do include generators. Generator Interconnections are not required to have FR, but generator breakers directly connected to an identified BES bus need to be included in SER data capture.

2. Are FRs required at all generating stations that are connected to the BES regardless of size and connected BES voltage? We believe installation of FR at generating facilities connected to voltages <200 kv is too aggressive and will impose significant resources requirements without contributing much benefit for the BES reliability. Has the feasibility of installing DME at a generating facility with one or two units to monitor 4-8 data points @ voltages <200 Kv been evaluated. While members of vertically integrated utilities can utilize a DME for both their transmission and generation data points, a non-vertically integrated generator owner is required by draft standard to install a DME for 3-4 data points. We suggest FR installation BES voltages greater than 200 kv with single generator rating of 500 MVA and an aggregate generation of 1500 MVA at a single site.

Response: FR is not required for generators and their interconnections to the BES. PRC-002-2 addresses "what" data is recorded, not "how" it is recorded. Requirement R3 specifies that the electrical quantities can be "determined." The Rationale Box and Guideline for Requirement R3 have been revised and provide clarification.

3. The initial standard drafting team had performed studies and was recommending FR and DDR installation at 345 kv and higher voltages based on specific requirements that supported improving BES stability and reliability. We ask that current SDT to demonstrate basis/rational for the DME (FR & DDR) need at all BES voltage levels. A rough breakdown statistics on number of FR that will be required by R1 and R3 of the draft standard and implied reliability benefit by each requirement at each BES voltage level will be very beneficial. Also, several NERC Regions had previously developed DME criteria with FR and DDR requirement at >200 KV BES voltage levels. The Only region will region with DME requirements at all BES voltages was NPCC. Has the SDT team discussed DME requirements by Region or interconnection?

Response: The Standard Drafting Team is aware of the requirements in the Regions. PRC-00-2 is designed to address the capturing of data, and having adequate data available to be able to determine disturbance quantities. PRC-002-2 addresses "what" data is captured, not "how" it is captured.

Portland General Electric Company
Angela Gaines

Portland General Electric appreciates the drafting team's efforts regarding the project. After additional review, PGE has no concerns regarding the proposed standard. The negative votes were cast in error.

Response: The Standard Drafting Team thanks you for your comment.

END OF REPORT

Standard Development Timeline

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

Development Steps Completed

1. Nominations for the SAR Drafting Team members were solicited February 26 – March 9, 2007.
2. The SAR was posted for a 30-day comment period March 22 – April 20, 2007.
3. Nominations for the Disturbance Monitoring Standard Drafting Team (DMSDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.
4. The draft standard was posted for a 45-day formal comment period February 2-March 18, 2009.
5. The project was placed into informal development the fall of 2010.
6. The project was placed into formal development January 2013.
7. Nominations for two additional DMSDT members were solicited April 12 – 25, 2013.
8. Three additional DMSDT members were added May 22, 2013.
9. Industry webinars were held May 22, 2013, June 12, 2014, and August 21, 2014.
10. Industry technical conferences were held July 30 - 31, 2013 and August 6 - 7, 2013.
11. The draft standard was posted for a 45-day concurrent comment and ballot period November 1 – December 16, 2013.
12. The draft standard was posted for a 45-day concurrent comment and ballot period May 9 – June 25, 2014 (ballot was extended to achieve quorum).

Description of Current Draft

This is the fourth draft of the proposed standard and is being posted for stakeholder comments and additional ballot. This draft includes the modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with a 10-day Ballot	September, 2014
Final Ballot	October, 2014
BOT Adoption	November, 2014

Effective Dates

See Implementation Plan

Version History

Version	Date	Action	Change Tracking
2.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms (Glossary) used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

When this standard has received ballot approval, the Rationale Boxes will be moved to the Guidelines and Technical Basis Section of the Standard.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

Functional Entities:

4.1 The Responsible Entity is:

4.1.1 Eastern Interconnection – Planning Coordinator

4.1.2 ERCOT – Planning Coordinator or Reliability Coordinator

4.1.3 Western Interconnection – Reliability Coordinator

4.2 Transmission Owner

4.3 Generator Owner

Rationale for Functional Entities:

When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required interval under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the in force list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

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

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

Rationale for R2:

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R3:

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1)

documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30 cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30 contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Responsible Entity has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Responsible Entity has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this Standard does not preclude the Responsible Entity from performing this re-evaluation more frequently to capture updated BES Elements.

The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.

The Responsible Entity must notify all owners of the selected BES Elements that DDR data is required for this Standard. The Responsible Entity is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Responsible Entity. Data for each BES Element as defined by the Responsible Entity must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Responsible Entities, each Responsible Entity will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Responsible Entities. It is intended that each Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R6:

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the ‘what’ of DDR, not the ‘how’. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings; or (2) actual data recordings (R9, Part 9.2).

Rationale for R9:

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

Rationale for R10:

NOTE: The rationale for R10 was extensively revised since the last posting. To make reading easier, only the clean version of the language is included here.

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

Rationale for R11:

NOTE: The rationale for R11 was extensively revised since the last posting. To make reading easier, only the clean version of the language is included here.

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date of the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by 10-calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by greater than 30-calendar days.

				owners by greater than 10-calendar days but less than or equal to 20-calendar days.	owners by greater than 20-calendar days but less than or equal to 30-calendar days.	
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 0 percent but less than or equal to 70 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified

			number of specified electrical quantities for each BES Element.	Elements and the number of specified electrical quantities for each BES Element.	Elements and the number of specified electrical quantities for each BES Element.	electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was

			5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by	The Generator Owner had DDR data as directed by	The Generator Owner had DDR data as directed by	The Generator Owner failed to have DDR data as directed by

			Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR

			OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	to 110-calendar days after discovery of the failure.	to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

Center this title =>

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RE (PC | RC)	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses “what” data is recorded, not “how” it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices

- Voltage sensitive areas
- Cohesive load and generation zones
- BES buses with a relatively high number of incident Transmission circuits
- BES buses with reactive power devices
- Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100 kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:
$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings
Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30 cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30 contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.

- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA”. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires “One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs).” Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area’s response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the Standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This

drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating

precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Responsible Entity, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the

data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

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

Development Steps Completed

1. Nominations for the SAR Drafting Team members were solicited February 26 – March 9, 2007.

2. The SAR was posted for a 30-day comment period March 22 – April 20, 2007.

3. Nominations for the Disturbance Monitoring Standard Drafting Team (DMSDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.

~~3.~~4. The draft standard was posted for a 45-day formal comment period February 2-March 18, 2009.

~~4.~~5. The project was placed into informal development the fall of 2010.

~~5.~~6. The project was placed into formal development January 2013.

~~6.~~7. Nominations for two additional DMSDT members were solicited April 12 – 25, 2013.

~~7.~~8. Three additional DMSDT members were added May 22, 2013.

~~8.~~9. Industry webinar was held May 22, 2013; June 12, 2014 and August 21, 2014.

~~9.~~10. Industry technical conferences were held July 30 - 31, 2013 and August 6 - 7, 2013.

11. The draft standard was posted for a 45-day concurrent comment and ballot period November 1 – December 16, 2013.

~~10.~~12. The draft standard was posted for a 45-day concurrent comment and ballot period May 9 – June 25, 2014 (ballot was extended to achieve quorum).

Description of Current Draft

This is the fourth~~second~~ draft of the proposed standard and is being posted for stakeholder comments and additional ballot. This draft includes the modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with a 10-day Ballot	September~~May~~ 2014
Final Ballot	October~~July~~ 2014
BOT Adoption	November~~August~~ 2014

Effective Dates

See Implementation Plan

~~The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~Implementation Plan~~.

~~Implementation Plan for PRC-002-2 Requirements R1 and R5:~~

~~Entities shall be 100% percent compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~Implementation Plan for PRC-002-2 Requirement R12:~~

~~Entities shall be 100~~ percent~~% compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:~~

~~Entities shall be at least 50%~~ percent ~~compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date.~~

~~Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the Effective Date.~~

~~Entities shall be 100%~~ percent ~~compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list.~~

Version History

Version	Date	Action	Change Tracking
2.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms (Glossary) used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

When this standard has received ballot approval, the Rationale Boxes will be moved to the Guidelines and Technical Basis Section of the Standard.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate ~~event~~ analysis of Bulk Electric System (BES) D~~d~~isturbances.
4. **Applicability:**

Functional Entities:

4.1 The Responsible Entity is:

4.1.1 Eastern Interconnection – Planning Coordinator

4.1.2 ERCOT – Planning Coordinator or Reliability Coordinator

4.1.3 Western Interconnection – Reliability Coordinator

4.2 Transmission Owner

4.3 Generator Owner

Rationale for Functional Entities:

When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic ~~d~~Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their ~~s~~Systems to determine tho~~e~~se buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. I~~i~~dentify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1;

1.2. ~~, n~~Notify other owners of BES Elements connected to those BES buses, if any, within 90-~~-~~calendar days of completion of Part 1.1 that those BES Elements ~~may~~ require SER data and/or FR data;~~, and~~

~~**1.1.**~~**1.3.** R~~r~~e-evaluate all ~~the identified~~ BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. ~~*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is~~are~~ required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all~~the~~ BES buses~~ identification~~ have~~s~~ been re-evaluated ~~-~~within the required interval under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. ~~Requirement R1~~Attachment 1 provides~~directs~~ a uniform methodology to identify tho~~e~~se BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a T~~t~~ransmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of T~~t~~ransmission L~~l~~ines and other Elements connected to the bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on ~~s~~System reliability and performance. ~~-~~Conversely, BES buses with very low short circuit MVA levels seldom cause ~~large~~ Wide-area or cascading ~~s~~System events, so SER and FR data from tho~~e~~se BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment. ~~-~~Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. ~~Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection.~~

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is~~are~~ required, based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. ~~-~~This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and ~~s~~System topology of Transmission Owners across all Interconnections. ~~–~~Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is~~are~~ required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their ~~s~~Systems to determine these buses. ~~SER and~~From ~~FR data will include generating resource contributions to an event~~ can be determined. ~~DDR data better shows generator response to disturbances.~~

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address ~~s~~System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the in force list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

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

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may~~can~~ include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

Rationale for R2:

The intent is to capture SER data for the status (open~~ing~~/close~~ing~~) o~~f~~~~or~~ the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized ~~common~~ clock, provides the basis for assembling the detailed sequence of events timeline of a power S~~s~~ystem ~~d~~Disturbance. Other status monitoring ~~indications~~nomenclature can be used for devices other than circuit breakers.

R3. Each Transmission Owner and Generator Owner shall have ~~the following~~ FR data to determine the following electrical quantities for each triggered FR for~~of~~ the BES Elements it~~they~~ owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage~~s~~ for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission ~~l~~Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include~~ing~~ a single design standard as a representation for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R3:

The required electrical quantities may either be directly measured or ~~derivable~~ determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for ~~s~~System D~~d~~isturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step up transformers (GSU) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from ~~the above~~Requirement R3 because the fault current contribution from a generator in case of fault on the T~~t~~ransmission ~~s~~System will be captured by FR data on the T~~t~~ransmission S~~s~~ystem, and T~~t~~ransmission ~~s~~System FR will see faults on the generator interconnection.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total ~~post-trigger~~ record length of at least 30 cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. ~~-~~Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power ~~s~~System operations and determination if operations were as designed. System faults generally persist for a short time period, thus, a 30 cycle ~~post-trigger~~total minimum record length is adequate. ~~-~~Multiple records allow for legacy microprocessor relays which, when time synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30 contiguous cycles total~~post-trigger~~.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 ~~shall I~~identify BES Elements for which dynamic ~~d~~Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element

5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, ~~connected to those BES buses, if any,~~ within 90~~-~~calendar days of completion of Part 5.1, that their respective ~~those~~ BES Elements ~~may~~ require DDR data when requested.

5.4 Reevaluate all~~the identified buses~~ BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan.

~~*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~

~~**5.1** The BES Elements shall include the following:~~

~~**5.1.1** Generating resource(s) with:~~

~~Gross individual nameplate rating greater than or equal to 500 MVA, or~~

~~Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.~~

~~**5.1.2** Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines:~~

- ~~Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection, or~~
- ~~Transfer Paths in the Western Interconnection Path Rating Catalog, or~~
- ~~Voltage stability limited transfer paths or load serving area, or~~
- ~~Interfaces between Balancing Authority Areas, or~~
- ~~Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC).~~

~~**5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.~~

~~**5.1.4** One or more BES Elements associated with Interconnection Reliability Operating Limits (IROLs).~~

~~**5.1.5** Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.~~

~~**5.2** The BES Elements shall include a minimum of:~~

~~**5.2.1** One BES Element.~~

~~**5.2.2** One additional BES Element for each additional 3,000 MW of its historical peak system Demand.~~

M5. The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, ~~identifi~~developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. ~~assessed within the required interval,~~ The Responsible Entity has dated evidence (electronic or hard copy) ~~of notification to~~that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3.~~of Elements identified in Requirement R5.~~ Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R5:

NOTE: The rationale for R5 was extensively revised since the last posting. To make reading easier, only the clean version of the language is included here.

DDR is used for capturing the Bulk Electric System transient and post-transient response following disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Responsible Entity has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding why an event occurred not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-assessment of the list is a reasonable interval for this review. Changes to the BES do not instigate inclusion into the existing list, and will be incorporated into the selection process at the subsequent re-assessment. However, this Standard does not preclude the Responsible Entity from performing this re-assessment more frequently to capture updated BES Elements.

The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage and BES Elements. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.

The Responsible Entity must notify all owners of the selected BES Elements that DDR data is required for this Standard. The Responsible Entity is only required to share the list of selected Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected Elements is required to ensure that the owners of the respective Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, and the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Responsible Entity. Data for each BES Element as defined by the Responsible Entity must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the Elements selected. For example, DDR data must be provided for at least one end of a Transmission Line or Generator Step-Up (GSU) transformer but not both ends. For an interconnection between two Responsible Entities, each Responsible Entity will consider this interconnection independently and are expected to work cooperatively to determine the BES Elements that require DDR data and how to monitor them. For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these Elements with DDR will facilitate thorough and informative event analysis of large disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Responsible Entities; it is intended that each Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

~~R5.~~R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5~~, to determine the following electrical quantities~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R6:

DDR~~ynamic disturbance recording~~ is used ~~for measurement of~~to measure transient response to ~~s~~System ~~d~~Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the buses within a location are at the same frequency one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a S~~s~~ystem configuration assuming all normally closed circuit breakers on a bus are closed.

~~R6.~~R7. Each Generator Owner shall have DDR data to determine the following electrical quantities ~~have DDR data~~ for each BES Element it owns~~,~~ for which it received ~~and is~~ notification~~ed according to~~ as identified in Requirement R5~~, to determine the following electrical quantities~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step up (GSU) transformer high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R7:

A crucial part of wide-area disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high or low-side of the generator step up (GSU) transformer, measuring the specified electrical quantities, to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

~~R7.~~R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

Rationale for R8:

Large scale ~~s~~System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

~~R8.~~R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet~~conforms to~~ the following~~ technical specifications~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification~~, and~~ device configuration, or settings;~~,~~ or

Rationale for R9:

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle~~,~~ on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power ~~s~~System ~~d~~Disturbances.

(2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and ~~,~~ FR~~ and DDR~~ data for the BES ~~-~~buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 that meet the following:~~o within ± 2 milliseconds of Coordinated Universal Time (UTC), time stamped with or without a local time offset.~~ *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC)~~,~~ with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification~~, and~~ configuration, or setting; ~~or~~ (2) time synchronization indication or status; or 3) station drawings~~actual data recordings~~.

Rationale for R10:

NOTE: The rationale for R10 was extensively revised since the last posting. To make reading easier, only the clean version of the language is included here.

Time synchronization of disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and~~,~~ FR~~, and DDR~~ data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity~~liability Coordinator~~, Regional Entity, or NERC in accordance with the following~~ requiremnts: as follows~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 ~~The recorded d~~Data will be retrievable for the period of 10 ~~-~~calendar days, inclusive of the day the data was recorded ~~preceding a request~~.

11.2 ~~The recorded d~~Data subject to Part 11.1 will be provided within 30 ~~-~~calendar days of a request unless and extension is granted by the requestor.

~~**11.2** The recorded data will be retrievable for the period of 10 calendar days preceding a request.~~

11.3 SER data will be provided in ASCII Comma Separated Value (~~-~~CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with~~electronic~~ C37.111, (~~C37.111-19992013 or later)~~ IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later~~formatted files~~.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME)~~.~~, revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records;~~,~~ (2) documents describing data storage capability, device specification,~~, and~~ configuration or settings;~~,~~ or (3) actual data recordings.

Rationale for R11:

NOTE: The rationale for R11 was extensively revised since the last posting. To make reading easier, only the clean version of the language is included here.

Wide-area disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-~~-~~calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10~~-~~calendar days inclusive of the day the data was recorded, i.e. a 10-day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10 calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requester of data has to be aware of the Part 11.1 10-day retrievability because requiring data retention for longer is expensive and unrealistic.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve a common data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing disturbance monitoring data. This file format allows a streamlined analysis of large disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

R12. Each Transmission Owner and Generator Owner shall, within 90-~~-~~calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- R~~r~~estore the recording capability, or ~~develop a timeline for restoration and a~~
- Submit a Corrective Action Plan (CAP) ~~for submission~~ to the Regional Entity and implement it. ~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date of the data recording was restored, (3) SCADA records, or (4~~3~~) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-~~-~~calendar days to ensure that adequate data is available for event analysis. ~~Therefore, it is required to return the data recording capability to service within 90 calendar days of a discovery of failure.~~ If the Disturbance Monitoring ~~Equipment (DME)~~ capability cannot be ~~returned to service~~restored within 90 calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the ~~E~~entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timetable~~line~~ required for the CAP depends on the entity and the type of data required.~~. , and the would be able to effectively manage the CAP. For example, DDR data from a generator may not be restored until the next outage cycle.~~ ~~I~~ It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days~~ that would be treated as a failure.~~.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per~~of~~ Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80% but less than 100% of the required BES buses that they own. OR The Transmission Owner evaluated ~~assessed~~ the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by 10-calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70% but less than or equal to 80% of the required BES buses that they own. OR The Transmission Owner evaluated ~~assessed~~ the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60% but less than or equal to 70% of the required BES buses that they own. OR The Transmission Owner evaluated ~~assessed~~ the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60% of the required BES buses that they own. OR The Transmission Owner evaluated ~~assessed~~ the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

				owners by greater than 10-~~-~~calendar days but less than or equal to 20-~~-~~calendar days.	owners by greater than 20-~~-~~calendar days but less than or equal to 30-~~-~~calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission or Generator Owner as directed by Requirement R2 had more than 80~~75~~% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission or Generator Owner as directed by Requirement R2 had more than 7~~5~~0% but less than or equal to 80~~75~~% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission or Generator Owner as directed by Requirement R2 had more than 6~~1~~0% but less than or equal to ~~5~~70% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission or Generator Owner as directed by Requirement R2 for ~~had from 0% but~~ less than or equal to 6~~1~~0% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80~~75~~% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than ~~5~~70% but less than or equal to 80~~75~~% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 6~~1~~0% but less than or equal to 7~~5~~0% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers ~~more than 0% but~~ less than or equal to 6~~1~~0% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the

			number of specified electrical quantities for each BES Element.	number of specified electrical quantities for each BES Element.	number of specified electrical quantities for each BES Element.	number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80~~75~~% but less than 100% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 7~~5~~0% but less than or equal to 80~~75~~% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 6~~1~~0% but less than or equal to 7~~5~~0% of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets ~~more than 0% but~~ less than or equal to 6~~1~~0% of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity ~~accurately~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80% but less than 100% of the required BES Elements included in Part 5.1. OR The Responsible Entity ~~assess~~identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was	The Responsible Entity ~~accurately~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required BES Elements included in Part 5.1. OR The Responsible Entity ~~assess~~identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30	The Responsible Entity ~~accurately~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required BES Elements included in Part 5.1. OR The Responsible Entity ~~assess~~identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60	The Responsible Entity ~~accurately~~ identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60% of the required BES Elements included in Part 5.1. OR The Responsible Entity ~~assess~~identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was

			late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	calendar days and less than or equal to 60-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80~~75~~% but less than 100% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 7~~5~~0% but less than or equal to 80~~75~~% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60% but less than or equal to 7~~5~~0% of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by	The Generator Owner had DDR data as directed by	The Generator Owner had DDR data as directed by	The Generator Owner failed to have DDR data as directed by

			Requirement R7, Parts 7.1 through 7.4 that covers more than 80~~75~~% but less than 100% of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4 for more than 7~~5~~0% but less than or equal to 80~~75~~% of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4 for more than 60% but less than or equal to 7~~5~~0% of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80~~75~~% but less than 100% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 7~~5~~0% but less than or equal to 80~~75~~% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60% but less than or equal to 7~~5~~0% of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80~~75~~% but less than 100% of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 7~~5~~0% but less than or equal to 80~~75~~% of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 6~~1~~0% but less than or equal to 7~~5~~0% of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 6~~1~~0% of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90% but less than 100% of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70% of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar ~~days~~ ~~from~~days after the request unless an extension was granted	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days ~~from~~ after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days ~~from~~ after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days ~~from~~ after the request unless an extension was granted by the requesting authority. OR

			by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11~~, Part 11.2~~ provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% of the data but less than 100% of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11~~, Part 11.2~~ provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% of the data but less than or equal to 90% of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11~~, Part 11.2~~ provided more than 70% but less than or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% of the data but less than or equal to 80% of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11~~, Part 11.2~~ failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% of the data in the proper data format.

R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to-120 calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111~~-2013, Measuring relays and protection equipment Part 24~~: Common format for transient data exchange (COMTRADE) for power systems.~~ Standard published 04/30/2013 by IEEE.~~

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for Sequence of Events Recording (SER) and Fault Recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20%.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1500 MVA or
- 20% of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than 11 ~~or fewer~~ BES buses: FR and SER data is required at the BES bus~~es~~ with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10% of the BES buses~~,~~ determined in Step 6~~,~~ with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20% of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner’s discretion, to provide maximum wide-area coverage for SER and FR data, therefore the following types of BES buses are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident T~~t~~ransmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner’s area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2
Sequence of Events Recording (SER) Data Format
(Requirement R11, Part 11.3)

~~Date~~	~~Time~~	~~Local Time Code Local Time Offset from UTC~~	~~Substation~~	~~Device~~	~~State~~[1]
~~08/27/13~~	~~23:58:57.110~~	-~~5EST~~	~~Sub 1~~	~~Breaker 1~~	~~Close~~
~~08/27/13~~	~~23:58:57.082~~	-~~5EST~~	~~Sub 2~~	~~Breaker 2~~	~~Close~~
~~08/27/13~~	~~23:58:47.217~~	-~~5EST~~	~~Sub 1~~	~~Breaker 1~~	~~Open~~
~~08/27/13~~	~~23:58:47.214~~	-~~5EST~~	~~Sub 2~~	~~Breaker 2~~	~~Open~~

Date, Time, Local Time Code, Substation, Device, State[1]
08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close
08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close
08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open
08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] ~~Acceptable states are either~~ "OPEN" and~~or~~ "CLOSE" are used as examples. ~~Other status monitoring indications can be used~~ Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.~~for devices other than circuit breakers~~.

~~Guidelines and Technical Basis~~

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Assessment
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Assessment
R5	RE (PC | RC)	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance Monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance Monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a ~~s~~System configuration assuming all normally closed circuit breakers on a bus are closed~~. ~~.

PRC-002-2 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault records for the analysis, reconstruction, and reporting of ~~s~~System ~~d~~Disturbances is important. However, SER and FR data are not required at every BES bus on the BES to conduct adequate or thorough analysis of a ~~d~~Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual ~~circuit sallow~~circuits allow precise reconstruction of events of both localized and wide-area D~~d~~isturbances.

In addition, more quality information is always better than less when performing event analysis. However, 100% coverage of all elements is not practical nor required for effective analysis of wide-area D~~d~~isturbance. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. ~~Excessive overlap of coverage is avoided.~~Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of ~~system~~ BES ~~e~~Elements that could propagate a D~~d~~isturbance.
5. Avoid mandates to cover ~~system~~ BES ~~e~~Elements that are more likely to be a casualty of a ~~d~~Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of T~~t~~ransmission ~~l~~Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish bright line criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of ~~t~~Transmission ~~s~~Systems throughout the continent to analyze ~~t~~Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright-line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause ~~electric system c~~Cascading ~~outages~~.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater ~~s~~System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for ~~s~~Systems with more than 11 BES buses with three phase short circuit levels above 1500 MVA.

1. Total number of BES buses in the T~~t~~ransmission S~~s~~ystem under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in ~~s~~System models are excluded.
2. Determine the three phase short circuit MVA for each bus.
3. Exclude buses from the list with short circuit levels below 1500 MVA.
4. Determine the median short circuit for the top 11 buses on the list (position number 6).
5. Multiply median short circuit level by 20%.
6. Reduce the list of BES buses with short circuit levels higher than 20% of the median.
7. Apply SER and FR at buses with short circuit levels in the top 10% of the list (from 6).
8. Apply SER and FR at buses at an additional 10% of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones

- BES buses with a relatively high number of incident T~~t~~ransmission circuits
- BES buses with reactive power devices
- Major facilities interconnecting outside the Transmission Owners' area.

For event analysis purposes, more valuable information is attained about generators and their response to ~~s~~System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The reevaluation interval of five years was chosen based upon the experience of the DMSDT to address changing S~~s~~ystem configurations while creating balance in the frequency of reevaluations.

Guideline for Requirement R2:

Analyses of wide-area D~~d~~isturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the D~~d~~isturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a bus is cleared regardless of a generator's loading. ~~SER data for generator breaker operations provides little useful data of generator loading.~~

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission L~~l~~ines

Only those Elements that are identified as BES as ~~identified~~ defined in the latest in~~-~~effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100 kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the T~~t~~ransmission S~~s~~ystem will be captured by FR data on the ~~t~~Transmission S~~s~~ystem.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the ~~t~~Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a T~~t~~ransmission ~~s~~System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120◦, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:

$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are ~~to be~~ recorded or accurately determined at applicable BES buses. ~~Note that the Requirement calls for the voltages to be determinable. There are two options for recording phase-to-neutral voltages at applicable BES buses:~~

~~1. At terminals of each line. This option would apply to lines that have a full set of VTs/CVTs required for distance protections, which is quite common in practice.~~

~~2. At a particular BES bus, in which case all the BES Elements connected to that common BES bus are covered.~~

Guideline for Requirement R4:

~~This requirement directs the applicable entities having FR determined as identified in Requirement R1 that meets the following:~~

~~Requirement R4, Part 4.1 specifies the minimum amount of FR data.~~ Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection ~~s~~System operations after a fault to determine if a protection S~~s~~ystem operated as designed. Generally speaking, BES faults ~~and the system's response to them~~ persist for~~occur within~~ a very short time period, approximately 1 to 30 cycles, thus a 30 cycle ~~post- trigger~~ record length provides~~captured~~ adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30 cycle ~~post trigger~~ data.

~~Requirement R4, Part 4.2 specifies the minimum recording rate of FR data.~~ A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for SER.

~~Requirement R4, Part 4.3 specifies the minimum triggers to ensure FR data is available. A trigger is a set point on an oscilloscope or FR device. The~~FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area ~~d~~Disturbance monitoring to determine the ~~s~~System's electromechanical transient and post-transient response and validate ~~s~~System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the ~~s~~System's dynamic response and ensuring sufficient coverage to determine ~~s~~System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historic peak Demand. This DDR data is included to provide adequate ~~s~~System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a D~~d~~isturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.
- The information in the spreadsheet does not provide information by which the plant location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47% of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5% of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, Part 5.1.2 is included to capture larger units located at large generating plants which could pose a stability risk to the S~~s~~ystem if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

~~Major transmission interfaces are explicitly defined based on the Interconnection since a common naming convention for these interfaces does not exist. However, this data may be calculated, rather than directly measured, if the accurate quantity can be derived (e.g. either end of the Flowgate line could be monitored since the other end could be derived). In the Western Interconnection, these major transmission interfaces are defined by the Regional Entity. In the ERCOT and Quebec Interconnections, the Responsible Entity will be required to identify those interfaces that are deemed significant enough to require monitoring (i.e. are utilized for real-time limits such as System Operating Limits or "contingencies"). Only one BES Element associated with a major transmission interface needs DDR data capability.~~

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability a have significant impact on the reliability and performance. Therefore, at least one BES Element of an SOL should be monitored. Interconnection Reliability Operating Limits (IROLs) are also included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored Element(s) and contingent Element(s). The Standard does not dictate whether the contingent and/or monitored Elements should be selected; rather, this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to ~~s~~System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored Element(s) and contingent Element(s). The Standard does not dictate whether the contingent and/or monitored Elements should be select; rather, the Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability could be captured on the BES. For example, a major 500kV or 230kV substation on the EHV S~~s~~ystem close to the load pocket where the UVLS is deployed would likely be a valuable BES Element for DDR coverage and would aid in post-disturbance analysis of the load area's response to large S~~s~~ystem deviations (voltage, frequency, etc.). ~~It is intended to have DDR data for "Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program."~~

Guideline for Requirement R6:

DDR data shows transient response to S~~s~~ystem D~~d~~isturbances after the fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the Standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double bus configuration that has a North (or East) Bus and South (or West) Bus,~~-~~ would require ~~that~~ both buses to~~should~~ have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a ~~s~~System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current record is also acceptable.

For all circuits where current recording is required, real and reactive power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6~~,~~ apply to Requirement R7. Since either~~ of~~ the high or low-side windings of the generator step up (GSU) transformer may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a S~~s~~ystem configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Large scale S~~s~~ystem outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high or low frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in ~~s~~System frequency which could be caused by large changes in generation or load, or possibly changes in S~~s~~ystem impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85% is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power Ssystem to a dDisturbance and is used for analyzing complex power Ssystem events. This recording is typically used to capture short term and long term Ddisturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency in sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other dDisturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of diDsturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Time synchronization Aaccuracy ~~of ±2 milliseconds for time synchronization~~ is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

~~The ±2 milliseconds accuracy requirement specified in this standard is realistically achievable with equipment available and proper cabling installation.~~

~~Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset.~~

Guideline for Requirement R11:

This requirement directs the applicable entities, ~~that~~ upon requests from the Responsible Entity~~liability Coordinator~~, Regional Entity or NERC, to provide SER ~~,~~and FR data for BES buses determined in requirement R1 and DDR data for BES Elements determined per requirement R5. To facilitate the analysis of BES D~~d~~isturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-~~-~~calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-~~-~~calendar days inclusive of the day the data was recorded for which the data will be retrievable ~~preceding a request~~. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-~~-~~calendar days ~~preceding a request is~~ realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-~~-~~calendar day time frame, an incident occurs on ~~a~~ Day 1. If a request for data is made on Day 6, then that data has to be provided to the requester within 30-~~-~~calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-~~-~~calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (~~.~~CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power ~~s~~System D~~d~~isturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and ~~it~~ is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources~~it~~ will be incorporated ~~with other submitted data~~ to provide a detailed analysis of a power ~~s~~System ~~d~~Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data. ~~is a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.~~

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for~~ the~~ naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files; the first version was approved in 2007. From the August 14, 2003 blackout there ~~was~~were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and ~~because of that it became~~was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and G~~g~~enerator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which had been established in Requirements R1 and R5.~~, and that are found to be out of service.~~ The owners are to restore~~turn~~ the capability ~~to service~~ within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out of service does not result in lack of sufficient data for coverage of the S~~s~~ystem. Furthermore, 90-~~-~~calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore~~turn~~ the capability ~~to service~~ within 90-calendar days, the requirement further provides that, for such cases, the entity submit ~~must develop a time~~table~~line and~~ a Corrective Action Plan (CAP) ~~for submission~~ to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Implementation Plan

Project 2007-11 Disturbance Monitoring

Requested Approvals
- PRC-002-2 Disturbance Monitoring and Reporting Requirements

Requested Retirements
- PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements
- PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting

Prerequisite Approvals
- None

Applicable Entities
- Planning Coordinator
- Reliability Coordinator
- Transmission Owner
- Generator Owner

Revisions to Defined Terms in the NERC Glossary
- None

Background
The Implementation Plan reflects consideration of the following:

1. This standard reflects the need for data, rather than equipment, with the understanding that the data is collected from Disturbance Monitoring Equipment distributed across the BES.
2. A significant amount of sequence of events recording (SER), fault recording (FR), and dynamic Disturbance recording (DDR) capability already exists on the BES. The monitoring requirements in this standard align with industry practices. Therefore, many existing recordings can satisfy the Requirements and Implementation Plan put forth.
3. Fault MVA data is readily available or calculable by the Transmission Owners for the BES buses they own. Therefore, six (6) months is adequate time for generating the list of BES buses following the methodology described in Attachment 1 (for Requirement R1).

4. Responsible entities have the relevant data and information pertaining to the BES Elements requiring DDR and six (6) months is adequate time for working with any affected entities and generating the list of BES Elements.
5. The nine (9) month time period for R12 includes the six (6) month implementation for R1 and R5, and a three (3) month additional time period to make notifications. The nine (9) months for R12 implementation is reasonable for the contents of that requirement.
6. A total percentage of BES buses and BES Elements established in Requirements R1 and R5 respectively are used in the Implementation Plan since these lists are explicitly created and readily available. It is expected that many monitoring requirements will become compliant without significant changes to recording capability.
7. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities.
8. Implementation of Disturbance monitoring recording following changes to the system are addressed by following re-evaluation of the lists as per Requirement R1 and Requirement R5.
9. Implementing SER, FR, and DDR capability may require scheduled outages for both Transmission Owners and Generator Owners. Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant. Meanwhile, Transmission Owners probably will have more BES Elements requiring SER, FR, and DDR and may have to schedule outages across the system. The Implementation Plan takes scheduling outages into account.
10. An entity owning only one (1) identified BES bus, BES Element, or generating unit is allowed six (6) years for implementation to accommodate normal outage schedules.
11. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities.

General Considerations

Each Transmission Owner and Generator Owner subject to PRC-018-1 shall maintain the ability to provide Disturbance monitoring data using current methods required by PRC-018-1 until the entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. As required in PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting, Requirement R1, Parts 1.1 and 1.2, it is expected that the Transmission Owner and Generator Owner will have those functionalities with regard to their current Disturbance data.

Effective Date

The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard(s) for Retirement

PRC-002-1 Midnight of the day immediately prior to the effective date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Each Transmission Owner, and Generator Owner shall maintain documentation to demonstrate compliance with PRC-018-1 until that entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2 and shall be applicable to an entity's Disturbance monitoring and reporting activities not yet transitioned to PRC-002-2. PRC-018-1 will be retired following full implementation of PRC-002-2 as noted below.

PRC-018-1 Midnight of the day immediately prior to six (6) years after the effective date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for PRC-002-2 Requirements R1 and R5:

Entities shall be 100 percent compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirement R12:

Entities shall be 100 percent compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:

Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.

Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.

Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated the list.

Conforming Changes to Other Standards

Where conflicts between the continent-wide standard PRC-002-2 and a regional standard exist, entities should comply with PRC-002-2. Conflicts will be addressed in the appropriate regional standards development process.

- PRC-002-2 Requirement R3 stipulates data must be captured by FR to determine electrical quantities. PRC-002-NPCC-01 Requirement R3 stipulates the recording of those quantities.
- PRC-002-2 Requirement R5 stipulates the capture of DDR data for HVDC. PRC-002-NPCC-01 does not specify HVDC for DDR.
- PRC-002-2 Requirement R8 recognizes DDR that is not continuous, and includes triggering data for DDR that is not continuous. PRC-002-NPCC-01 stipulates that dynamic Disturbance recorders installed after that standard was approved have to be continuous, but does not address legacy devices.

Implementation Plan

Project 2007-11 Disturbance Monitoring

Requested Approvals

- PRC-002-2 Disturbance Monitoring and Reporting Requirements

Requested Retirements

- PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements
- PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting

Prerequisite Approvals

- None

Applicable Entities

- Planning Coordinator
- Reliability Coordinator
- Transmission Owner
- Generator Owner

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan reflects consideration of the following:

1. This standard reflects the need for data, rather than equipment, with the understanding that the data is collected from Disturbance Monitoring Equipment distributed across the BES.
2. A significant amount of sequence of events recording (SER), fault recording (FR), and dynamic ~~d~~Disturbance recording (DDR) capability already exists on the BES. The monitoring requirements in this standard align with industry practices. Therefore, many existing recordings can satisfy the Requirements and Implementation Plan put forth.
3. Fault MVA data is readily available or calculable by the Transmission Owners for the BES buses they own. Therefore, six (6) months is adequate time for generating the list of BES buses ~~locations~~ following the methodology described in Attachment 1 (for Requirement R1).

4. Responsible ~~E~~entities have the relevant data and information pertaining to the BES Elements requiring DDR and six (6) months is adequate time for working with any affected entities and generating the list of BES Elements.
5. The nine (9) month time period for R12 includes the six (6) month implementation for R1 and R5, and a three (3) month additional time period to make notifications. The nine (9) months for R12 implementation is reasonable for the contents of that requirement.
6. A total percentage ~~(%)~~ of BES buses and BES Elements established in Requirements R1 and R5 respectively~~,~~ are used in the Implementation Plan since these lists are explicitly created and readily available. It is expected that many monitoring requirements will become compliant without significant ~~incremental~~ changes to recording capability.
7. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the ~~E~~entities.
8. Implementation of ~~d~~Disturbance monitoring recording following changes to the system are addressed by following re-evaluation~~assessment~~ of the lists as per Requirement R1 and Requirement R5.
9. Implementing SER, FR, and DDR capability may require scheduled outages for both Transmission Owners and Generator Owners. Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant. Meanwhile, Transmission Owners probably will have more BES Elements requiring SER, FR, and DDR and may have to schedule outages across the system. The Implementation Plan takes scheduling outages into account.
10. An ~~E~~entity owning only one (1) identified BES bus, BES Element, or generating unit is allowed six (6) years for implementation to accommodate normal outage schedules.
11. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective ~~E~~entities.

General Considerations

Each Transmission Owner and Generator Owner subject to PRC-018-1 shall maintain the ability to provide Disturbance monitoring data using current methods required by PRC-018-1 until the entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. As required in PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting, Requirement R1, Parts 1.1 and 1.2, it is expected that the Transmission Owner and Generator Owner will have those functionalities with regard to their current Disturbance data.

Effective Date

The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard(s) for Retirement

PRC-002-1 Midnight of the day immediately prior to the ~~E~~effective ~~D~~date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Each Transmission Owner, and Generator Owner shall maintain documentation to demonstrate compliance with PRC-018-1 until that entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2 and shall be applicable to an entity's Disturbance ~~M~~monitoring and ~~R~~reporting activities not yet transitioned to PRC-002-2. PRC-018-1 will be retired following full implementation of PRC-002-2 as noted below.

PRC-018-1 Midnight of the day immediately prior to six (6) years after the ~~E~~effective ~~D~~date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for PRC-002-2 Requirements R1 and R5:

Entities shall be 100~~%~~ percent compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirement R12:

Entities shall be 100~~%~~ percent compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:

Entities shall be at least 50~~%~~ percent compliant within four (4) years of the ~~E~~effective ~~D~~date of PRC-002-2 and fully compliant within six (6) years of the ~~E~~effective ~~D~~date.

Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the ~~E~~effective ~~D~~date.

Entities shall be 100~~%~~ percent compliant with a re-evaluated~~assessed~~ list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated ~~of~~ the list.

Conforming Changes to Other Standards

Where conflicts between the continent-wide standard PRC-002-2 and a regional standard exist, entities should comply with PRC-002-2. Conflicts will be addressed in the appropriate regional standards development process.

- ~~The following conflicts~~ PRC-002-2 Requirement R3 stipulates data must be captured by FR~~fault recording~~ to determine electrical quantities. PRC-002-NPCC-01 Requirement R3 stipulates the recording of those quantities.
- PRC-002-2 Requirement R5 stipulates the capture of DDR~~dynamic disturbance recording~~ data for HVDC. PRC-002-NPCC-01 does not specify HVDC for DDR.
- PRC-002-2 Requirement R8 recognizes ~~dynamic disturbance recording~~DDR that is not continuous, and includes triggering data for DDR that is not continuous. PRC-002-NPCC-01 stipulates that ~~addresses~~ dynamic ~~d~~Disturbance recorders installed after that ~~e~~ standard was approved have to be continuous, but does not address ~~mention~~ legacy devices.

The DMSDT developed this Excel Workbook is designed to assist Transmission Owners in using the Median Method for determining monitoring bus locations for Fault Recording and Sequence of Events Recording on their individual systems.

Instructions for use:

For Transmission Owners Only:

1	Organize your short circuit data in the format shown on the Data Input worksheet
2	Your short circuit data should use three phase short circuit with your selected pre-fault voltage
3	Your short circuit data should be ordered from highest three phase short circuit MVA value to lowest three phase short circuit MVA value for all buses greater than 100 kV
4	Your short circuit data should either eliminate or commonly identify non-real buses, zero buses, pseudo buses, or buses which are used for modeling purposes only, by using a common designation for all these type buses that can be eliminated from the Median calculation. It is most common to identify these non-real buses with the number "0" in the bus coded number field.
5	The Data Input Worksheet is designed to have you copy your properly formatted and sorted three phase MVA short circuit data into rows starting at column A row 6 of the worksheet.
6	Data Input, Col. F, is the most important column, it must have the three phase MVA short circuit data values, sorted from highest MVA to lowest MVA. The MVA values in column F, as sorted from highest to lowest MVA, should include all voltage levels greater than or equal to 100 kV.
7	Once you input all of your short circuit data into the Data Input worksheet starting at Column A Row 6, the values in cells B2, B3 and B4 should all be equal. These values should equal the number of rows of short circuit data that you have input. Copy Cell B2 using Cntrl C, then Paste Value, Special value only, back into Cell B2. This should be the total number of rows contained in the data set.
8	If you have zero numbered buses, or pseudo buses, commonly identified by say a number 0 in the bus coded number column, then you need to determine the number of zero numbered buses that are included in this data set.
9	For you to be able to determine this zero bus coded number, you need to select your entire data set, including the header row, from column / row A5 to G___(last row of data). As an example, if your data contains 100 rows, then your highlighted area for sorting and filtering should be A5 to G105. Then using the sort filter command, turn on Filter
10	Once the Filter is on, go to the bus coded number column, pull down the Filter and select only the zero bus coded number rows. The values in cells B3, and B4 should now be equal and indicate the number of zero numbered buses in your data set.
11	We want to store the zero numbered bus rows (number) into cell B4 as a value. To do this, select Cell B4, hit Cntrl C, then hit paste special, value only. This now repalces the formula in Cell B4 with the value of zero buses in the data set.
12	Now we wish to eliminate the zero bus rows from the rest of our data processing, so in the bus coded number column, we want to filter out the zero bus rows, so we reverse the pull down selection by selecting all rows, except the zero bus coded numbered rows. Leave this Filter in place for the rest of the Median method process.
13	If Cell B4 contains the number zero, then Cell F2 should now contain the 6th value down from the highest short circuit MVA value, and Cell G2 should contain 20% of the Cell F2 value. If Cell F2's value is greater than 1500 MVA this is the new lowest MVA value to be used to determine the number of Median selected buses. If the value in F2 is less than 1500 MVA, then we will use 1500 MVA as the lowest value to select the number of Median buses.
14	If Cell B4 contains a value greater than zero, then Cell F2 needs to be replaced with the MVA value contained in the 11th row, column F of the filtered data set. If the value in F2 is less than 1500 MVA then we will use 1500 MVA as the lowest value to select the number of Median buses.
15	With the Filter still applied to our data set, and zero buses deselected, we will need to use the F2 value to apply as the value used for the MVA column pull down.
16	Using Column F, MVA value pull down, use the Number Filter function, greater than or equal to the F2 value. With this Filter F2 number value applied, now Cntrl C Cell C2, and replace C2 with paste special, value only. This now is the number of buses selected by the Median method.
17	You are Finished!!! The number in Cell C2 indicates the number of Median method selected buses, D2 contains the number of total FR and SOER locations, E2 shows the number of FR / SOER for the Top 10% buses and F2 shows the number of FR / SOER for the Distributed 10% buses.
Notes:	Example 1 (Ex 1 without zero buses) is an additional worksheet shown for a system that does not contains any zero buses. All zero bus entries have been eliminated from the data set.
Notes:	Example 2 (Ex 2 with zero buses) is an additional worksheet shown for a system that contains zero buses. Note for a system that contains zero buses, you must observe the row 11, column F MVA value, and place it into Cell F2. In example 2, this MVA value is equal to 5685 MVA, based on the data set provided.

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	0	1	1	0	0	1500
Median Method	0	1	1	0		1500
Zero Busses	0	0	0	0		
Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**	

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	96	20	10	10	5685	1500
Median Method	64	13	7	6		1500
Zero Busses	0	0	0	0		

Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**
19	NCR ID#	FRCC	230	31120	12397
319	NCR ID#	FRCC	230	23087	9197
52	NCR ID#	FRCC	230	17615	7017
58	NCR ID#	FRCC	230	17039	6788
56	NCR ID#	FRCC	230	16472	6562
23	NCR ID#	FRCC	230	14271	5685
31	NCR ID#	FRCC	230	14018	5584
295	NCR ID#	FRCC	115	27868	5551
294	NCR ID#	FRCC	115	27828	5543
315	NCR ID#	FRCC	230	13810	5502
312	NCR ID#	FRCC	230	12018	4788
51	NCR ID#	FRCC	230	10785	4296
316	NCR ID#	FRCC	230	10616	4229
314	NCR ID#	FRCC	230	10558	4206
320	NCR ID#	FRCC	230	10552	4204
53	NCR ID#	FRCC	230	10342	4120
317	NCR ID#	FRCC	230	10279	4095
302	NCR ID#	FRCC	230	10103	4025
55	NCR ID#	FRCC	230	10076	4014
59	NCR ID#	FRCC	230	9713	3869
304	NCR ID#	FRCC	230	9618	3831
60	NCR ID#	FRCC	230	9605	3826
299	NCR ID#	FRCC	230	9598	3823
303	NCR ID#	FRCC	230	9542	3801
54	NCR ID#	FRCC	230	9110	3629
231	NCR ID#	FRCC	115	14835	2955
215	NCR ID#	FRCC	115	14296	2848
269	NCR ID#	FRCC	115	13212	2632
309	NCR ID#	FRCC	115	12895	2568
230	NCR ID#	FRCC	115	12889	2567
301	NCR ID#	FRCC	115	12781	2546
266	NCR ID#	FRCC	115	12723	2534
238	NCR ID#	FRCC	115	12674	2525
260	NCR ID#	FRCC	115	12674	2525
306	NCR ID#	FRCC	115	11990	2388

271	NCR ID#	FRCC	115	11826	2356
249	NCR ID#	FRCC	115	11049	2201
247	NCR ID#	FRCC	115	10975	2186
246	NCR ID#	FRCC	115	10902	2171
313	NCR ID#	FRCC	115	10868	2165
262	NCR ID#	FRCC	115	10472	2086
242	NCR ID#	FRCC	115	10243	2040
228	NCR ID#	FRCC	115	10089	2010
248	NCR ID#	FRCC	115	9865	1965
217	NCR ID#	FRCC	115	9560	1904
297	NCR ID#	FRCC	115	9521	1896
209	NCR ID#	FRCC	115	9295	1851
243	NCR ID#	FRCC	115	8969	1787
218	NCR ID#	FRCC	115	8926	1778
265	NCR ID#	FRCC	115	8913	1775
232	NCR ID#	FRCC	115	8882	1769
210	NCR ID#	FRCC	115	8875	1768
240	NCR ID#	FRCC	115	8538	1701
239	NCR ID#	FRCC	115	8442	1681
307	NCR ID#	FRCC	115	8397	1673
270	NCR ID#	FRCC	115	8349	1663
272	NCR ID#	FRCC	115	8193	1632
258	NCR ID#	FRCC	115	8000	1593
310	NCR ID#	FRCC	115	7891	1572
211	NCR ID#	FRCC	115	7837	1561
261	NCR ID#	FRCC	115	7822	1558
225	NCR ID#	FRCC	115	7730	1540
234	NCR ID#	FRCC	115	7557	1505
233	NCR ID#	FRCC	115	7543	1502
204	NCR ID#	FRCC	115	7386	1471
259	NCR ID#	FRCC	115	7374	1469
256	NCR ID#	FRCC	115	7314	1457
298	NCR ID#	FRCC	115	7258	1446
244	NCR ID#	FRCC	115	7249	1444
222	NCR ID#	FRCC	115	7204	1435
223	NCR ID#	FRCC	115	7133	1421
263	NCR ID#	FRCC	115	7118	1418
226	NCR ID#	FRCC	115	6989	1392
254	NCR ID#	FRCC	115	6913	1377
267	NCR ID#	FRCC	115	6851	1365
257	NCR ID#	FRCC	115	6846	1364
253	NCR ID#	FRCC	115	6772	1349
245	NCR ID#	FRCC	115	6704	1335
308	NCR ID#	FRCC	115	6571	1309
251	NCR ID#	FRCC	115	6473	1289
241	NCR ID#	FRCC	115	6395	1274
252	NCR ID#	FRCC	115	5556	1107

255	NCR ID#	FRCC	115	5007	997
5	NCR ID#	FRCC	13.2	39503	903
9	NCR ID#	FRCC	13.2	39501	903
13	NCR ID#	FRCC	13.2	39501	903
1	NCR ID#	FRCC	13.2	39492	903
17	NCR ID#	FRCC	13.2	39473	902
6	NCR ID#	FRCC	13.2	39306	899
10	NCR ID#	FRCC	13.2	39304	899
14	NCR ID#	FRCC	13.2	39304	899
2	NCR ID#	FRCC	13.2	39295	898
18	NCR ID#	FRCC	13.2	39276	898
214	NCR ID#	FRCC	115	4498	896
250	NCR ID#	FRCC	115	4329	862
318	NCR ID#	FRCC	13.2	13238	303

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	120	24	12	12	5685	1500
Median Method	64	13	7	6		1500
Zero Busses	24	5	3	2		
Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**	
19	NCR ID#	FRCC	230	31120	12397	
319	NCR ID#	FRCC	230	23087	9197	
52	NCR ID#	FRCC	230	17615	7017	
58	NCR ID#	FRCC	230	17039	6788	
56	NCR ID#	FRCC	230	16472	6562	
23	NCR ID#	FRCC	230	14271	**5685**	
31	NCR ID#	FRCC	230	14018	5584	
295	NCR ID#	FRCC	115	27868	5551	
294	NCR ID#	FRCC	115	27828	5543	
315	NCR ID#	FRCC	230	13810	5502	
312	NCR ID#	FRCC	230	12018	4788	
51	NCR ID#	FRCC	230	10785	4296	
316	NCR ID#	FRCC	230	10616	4229	
314	NCR ID#	FRCC	230	10558	4206	
320	NCR ID#	FRCC	230	10552	4204	
53	NCR ID#	FRCC	230	10342	4120	
317	NCR ID#	FRCC	230	10279	4095	
302	NCR ID#	FRCC	230	10103	4025	
55	NCR ID#	FRCC	230	10076	4014	
59	NCR ID#	FRCC	230	9713	3869	
304	NCR ID#	FRCC	230	9618	3831	
60	NCR ID#	FRCC	230	9605	3826	
299	NCR ID#	FRCC	230	9598	3823	
303	NCR ID#	FRCC	230	9542	3801	
54	NCR ID#	FRCC	230	9110	3629	
231	NCR ID#	FRCC	115	14835	2955	
215	NCR ID#	FRCC	115	14296	2848	
269	NCR ID#	FRCC	115	13212	2632	
309	NCR ID#	FRCC	115	12895	2568	
230	NCR ID#	FRCC	115	12889	2567	
301	NCR ID#	FRCC	115	12781	2546	
266	NCR ID#	FRCC	115	12723	2534	
260	NCR ID#	FRCC	115	12674	2525	
238	NCR ID#	FRCC	115	12674	2525	
306	NCR ID#	FRCC	115	11990	2388	
271	NCR ID#	FRCC	115	11826	2356	

249	NCR ID#	FRCC	115	11049	2201
247	NCR ID#	FRCC	115	10975	2186
246	NCR ID#	FRCC	115	10902	2171
313	NCR ID#	FRCC	115	10868	2165
262	NCR ID#	FRCC	115	10472	2086
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217	NCR ID#	FRCC	115	9560	1904
297	NCR ID#	FRCC	115	9521	1896
209	NCR ID#	FRCC	115	9295	1851
243	NCR ID#	FRCC	115	8969	1787
218	NCR ID#	FRCC	115	8926	1778
265	NCR ID#	FRCC	115	8913	1775
232	NCR ID#	FRCC	115	8882	1769
210	NCR ID#	FRCC	115	8875	1768
240	NCR ID#	FRCC	115	8538	1701
239	NCR ID#	FRCC	115	8442	1681
307	NCR ID#	FRCC	115	8397	1673
270	NCR ID#	FRCC	115	8349	1663
272	NCR ID#	FRCC	115	8193	1632
258	NCR ID#	FRCC	115	8000	1593
310	NCR ID#	FRCC	115	7891	1572
211	NCR ID#	FRCC	115	7837	1561
261	NCR ID#	FRCC	115	7822	1558
225	NCR ID#	FRCC	115	7730	1540
234	NCR ID#	FRCC	115	7557	1505
233	NCR ID#	FRCC	115	7543	1502

Unofficial Comment Form

Project 2007-11 Disturbance Monitoring

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by 8 p.m. Eastern on **October 21, 2014**.

If you have questions please contact Stephen Crutchfield via email or by telephone at 609-651-9455.

Click here for the Project Page.

Background Information

Project 2007-11 Disturbance Monitoring was initiated to replace the existing fill-in-the-blank Standard PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements with a more comprehensive standard. (Fill-in-the-blank standards are those standards that depend on regional criteria or procedures not currently contained within certain Reliability Standards, but which are needed to provide additional requirements for implementing the standards within the regions.) The DMSDT posted a draft standard for a 45-day comment/ballot period May 9- June 25, 2014. Based on the comments received from stakeholders, the DMSDT has revised the standard.

The DMSDT has performed significant outreach to better understand issues raised by stakeholders during the most recent posting and ballot period. This has resulted in revisions to the requirements, measures and rationales of the standard. One major point of emphasis is that the Transmission Owner or Generator Owner only has to be able to determine the quantities specified in the appropriate requirements.

The major issues related to PRC-002-2 that were raised by stakeholders include:

Commenters suggested that Requirement R1 should be separated into distinct Parts rather than having the requirement contained in a single sentence. The DMSDT revised R1 to contain distinct Parts:

R1. Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

- **1.1.** Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1;
- **1.2.** Notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data;

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

Some stakeholders voiced their concerns for more precise wording of Step 7 in previously posted Attachment 1 which stated “If the list has 11 or fewer BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA.” The ambiguity arose out of the term “buses” because it could be read as requiring FR and SER data from more than one bus. Thus, Step 7 is now revised to read “If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA.”

Commenters suggested clarifications to the rationales and a few of the requirements. The DMSDT has made extensive revisions to the rationales for Requirements R5, R10 and R11. These revisions provide clarity with regard to BES buses for DDR data, time synchronization for DDR and the length of time DDR data must be made available. Because of the extensive revisions made, the contents of the Rationale Boxes are “clean”.
Many stakeholders were unhappy with the bulleted list in Requirement R5, Part 5.1.2, either with a single bullet or with the list altogether. The standard DMSDT revised Requirement R5, Part, 5.1.2 and removed the bulleted list of “or” statements, replacing it with “Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).”

In Requirement R5, the use of “BES buses” was found to be confusing by many stakeholders. The use of this language was simply to provide clarity but, in response to industry’s comments, the DMSDT revised R5 by removing “BES buses”. The Requirement now references only BES Elements.

One technical change many stakeholders proposed was to revise Requirement R10 to relate to time synchronization of the device clock rather than data. The Requirement’s original language called for time synchronization of SER data within +/- 2 milliseconds. Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices are within ± 2 ms accuracy will suffice with respect to providing time synchronized data. The DMSDT revised Requirement R10 accordingly.

Several stakeholders also commented that Requirement R11 had no substantial impact on improving the reliability of the system. The DMSDT notes that the Requirement R11 ensures data availability from the data sources, timely retrievability of the data and common format so that the data can be read and used in the expeditious and effective analysis of events. Requirement R11 provides a reliability impact by integrating all of the previous requirements in the standard with respect to data reporting to facilitate event analysis. The first two Parts of Requirement R11 specify how long an entity has to provide requested data (Part 11.1) and also limits how long data must be retained by the TO or GO (Part 11.2). Parts 11.3-11.5 ensure the uniformity and consistency of the data that is reported.

Based on stakeholder feedback, the DMSDT capitalized the defined terms System, Transmission and Disturbance. The DMSDT believes that this adds clarity regarding the requirements and rationales in PRC-002-2. In some instances, these terms appear adjacent to each other within sentences of Requirements, Rationales or Guidelines. The following instances occur:

- Transmission System
- System Disturbance
- System Demand

The DMSDT has also incorporated the defined term “Transmission Line”. The DMSDT does not intend to create any new defined terms by the above uses. Each defined term stands on its own.

**Please use the* [electronic form](#) *to submit your final comments to NERC.*

You do not have to answer all questions. Enter All Comments in Simple Text Format.
Bullets, numbers, and special formatting will not be retained. Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The DMSDT revised the requirements for dynamic Disturbance recording (DDR) data based on stakeholder comments (see background section above). Do you agree with the BES Elements requiring DDR data listed in Requirement R5? If not, please provide technical justification.

☐ Yes
☐ No
Comments:

2. The DMSDT revised Requirements R10 regarding time synchronization of data and added explanation regarding time synchronization as follows to the rationale:

> "Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the standard devices used for monitoring are within ± 2 ms accuracy will suffice with respect to providing time synchronized data."

Do you support these revisions? If not, please explain why and provide suggested changes.

☐ Yes
☐ No
Comments:

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

A. Introduction

1. **Title:** **Define Regional Disturbance Monitoring and Reporting Requirements**
2. **Number:** PRC-002-1
3. **Purpose:** Ensure that Regional Reliability Organizations establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of Disturbance data to facilitate analyses of events and verify system models.
4. **Applicability**
   4.1. Regional Reliability Organization.
5. **Effective Date:** Nine months after BOT adoption.

B. Requirements

R1. The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:

R1.1. Location, monitoring and recording requirements, including the following:

R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R1.1.2. Devices to be monitored.

R2. The Regional Reliability Organization shall establish the following installation requirements for fault recording:

R2.1. Location, monitoring and recording requirements, including the following:

R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R2.1.2. Elements to be monitored at each location.

R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R2.1.3.1. Three phase to neutral voltages.

R2.1.3.2. Three phase currents and neutral currents.

R2.1.3.3. Polarizing currents and voltages, if used.

R2.1.3.4. Frequency.

R2.1.3.5. Megawatts and megavars.

R2.2. Technical requirements, including the following:

R2.2.1. Recording duration requirements.

R2.2.2. Minimum sampling rate of 16 samples per cycle.

R2.2.3. Event triggering requirements.

R3. The Regional Reliability Organization shall establish the following installation requirements for dynamic Disturbance recording:

R3.1. Location, monitoring and recording requirements including the following:

R3.1.1. Criteria for equipment location giving consideration to the following:

- Site(s) in or near major load centers
- Site(s) in or near major generation clusters
- Site(s) in or near major voltage sensitive areas
- Site(s) on both sides of major transmission interfaces
- A major transmission junction
- Elements associated with Interconnection Reliability Operating Limits
- Major EHV interconnections between control areas
- Coordination with neighboring regions within the interconnection

R3.1.2. Elements and number of phases to be monitored at each location.

R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R3.1.3.1. Voltage, current and frequency.

R3.1.3.2. Megawatts and megavars.

R3.2. Technical requirements, including the following:

R3.2.1. Capability for continuous recording for devices installed after January 1, 2009.

R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.

R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following:

R4.1. Criteria for events that require the collection of data from DMEs.

R4.2. List of entities that must be provided with recorded Disturbance data.

R4.3. Timetable for response to data request.

R4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE[1] analysis tool,

R4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files[2].

R4.6. Data content requirements and guidelines.

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[1] IEEE C37.111-1999 IEEE Standard Common Format for Transient Data Exchange for Power Systems or its successor standard

[2] Compliance with this requirement is not effective until the IEEE Standard is approved.

R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.

R6. The Regional Reliability Organization shall periodically (at least every five years) review, update and approve its Regional requirements for Disturbance monitoring and reporting.

C. Measures

M1. The Regional Reliability Organization's requirements for the installation of Disturbance Monitoring Equipment shall address Requirements 1 through 3.

M2. The Regional Reliability Organization's Disturbance monitoring data reporting requirements shall include all elements identified in Requirements 4.

M3. The Regional Reliability Organization shall have evidence it provided its Regional Disturbance monitoring and reporting requirements as required in Requirement 5.

M4. The Regional Reliability Organization shall have evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its DME requirements for three years.

The Compliance Monitor will retain its audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through providing its documentation of Disturbance Monitoring and Reporting requirements or self-certification as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exist:

2.1.1 Disturbance data reporting requirements were not specified as required in R4.1 through R4.6.

2.1.2 No evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in R6.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions exist:

2.2.1 Technical requirements were not specified for one or more types of DMEs.

2.2.2 Requirements do not provide criteria for equipment location or criteria for monitored elements or monitored quantities as required R1, R2 and R3.

2.3. Level 3: Not applicable.

2.4. Level 4: Disturbance monitoring and reporting requirements were not available or were not provided to Transmission Owners and Generator Owners.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Disturbance Monitoring Equipment Installation and Data Reporting**

2. **Number:** PRC-018-1

3. **Purpose:** Ensure that Disturbance Monitoring Equipment (DME) is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

5. **Effective Dates:** Phased in over four years after BOT adoption:

   Requirements 1 and 2:

   – 50% compliant two years after initial issuance of regional requirements per RELIABILITY STANDARD PRC-002 Requirement 5.

   – 75% compliant three years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   – 100% compliant four years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   Requirements 3 through 6:

   – 100% compliant six months after BOT adoption for already installed DME.

   – 100% compliant six months after installation for DMEs installed to meet Regional Reliability Organization requirements per reliability standard PRC-002 Requirements 1, 2 and 3.

B. Requirements

R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:

R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)

R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days..

R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).

R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):

R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).

R3.2. Make and model of equipment.

R3.3. Installation location.

R3.4. Operational status.

R3.5. Date last tested.

R3.6. Monitored elements, such as transmission circuit, bus section, etc.

R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc.

R3.8. Monitored electrical quantities, such as voltage, current, etc.

R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).

R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.

R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:

R6.1. Maintenance and testing intervals and their basis.

R6.2. Summary of maintenance and testing procedures.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have evidence that DMEs it is required to have meet the functional requirements specified in Requirement 1 and are installed in accordance with its associated Regional Reliability Organization's requirements (R2).

M2. The Transmission Owner and Generator Owner shall each maintain the data listed in Requirements 3.1 through 3.8 for the DMEs installed to meet its Regional Reliability Organization's DME installation requirements.

M2.1 The Transmission Owner and Generator Owner shall each have evidence it provided this DME data to its Regional Reliability Organization within 30 calendar days of a request.

M3. The Transmission Owner and Generator Owner shall each have evidence it retained and provided recorded Disturbance data to entities in accordance with its associated Regional Reliability Organization's Disturbance data reporting requirements. (R4 R5)

M4. Each Transmission Owner and Generator Owner that is required to install DMEs to meet its Regional Reliability Organization's DME installation requirements, shall have an associated DME maintenance and testing program as defined in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each retain any Disturbance data provided to the Regional Reliability Organization (Requirement 4) for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions is present:

2.1.1 DMEs that meet all the Regional Reliability Organization's installation requirements (in accordance with Requirement 2) were installed at 90% or more but not all of the required locations.

2.1.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with Requirement 4) was provided for 90% or more but not all of the required locations.

2.1.3 Data on required DMEs was incomplete (in accordance with R3)

2.1.4 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 80% or more but less than 90% of the required locations.

2.2.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 80% or more but less than 90% of the required locations.

2.2.3 Recorded Disturbance data was not provided to all required entities (in accordance with R4)

2.2.4 Archived data was not retained for three years (in accordance with Requirement 5).

2.2.5 Documentation of the DME maintenance and testing program provided was complete as required in R6, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions is present:

2.3.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 70% or more but less than 80% of the required locations.

2.3.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 70% or more but less than 80% of the required locations.

2.3.3 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. Level 4: There shall be a level four non-compliance if any one of the following conditions is present:

2.4.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at less than 70% of the required locations.

2.4.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for less than 70% of the required locations.

2.4.3 DMEs that meet all functional requirements (in accordance with R1) were not installed at all required locations.

2.4.4 Documentation of the DME maintenance and testing program was not provided, or no evidence that the testing program did occur within the identified intervals

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Consideration of Issues and Directives

Project 2007-11 Disturbance Monitoring
PRC-002-2 Disturbance Monitoring and Reporting Requirements

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"For the reasons stated in the NOPR, the Commission will not approve or remand PRC-002-1." "We agree with [American Public Power Association], Alcoa and Otter Tail that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards. Consistent with that goal, the Commission directs the ERO to consider APPA, Alcoa and Otter Tail's suggestions in the Reliability Standards development process as it modifies PRC-002-1 to provide missing information needed for the Commission to act on this Reliability Standard." (see below for American Public Power Association, Alcoa, and Otter Tail discussion)	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1455-56	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances. The use of recording and specifying recording data parameters, greater consistency is achieved in PRC-002-2.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in addressing the completion of this Reliability Standard."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1452	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances.
"Alcoa suggests that the ERO—instead of a Regional Entity—should define the requirements for DME and the type of report it generates. The requirements and equipment specifications should be consistent throughout North America. In addition, Alcoa suggests that the criteria for installation of such equipment should include the necessary monitoring and recording that contribute to analysis and enhance reliability."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1453	Determines the key locations for which Disturbance data must be recorded which eliminates the need for equipment requirements. PRC-002-2 specifies the storage requirements and recording format for the collected data to ensure continent-wide uniformity to expedite event analysis.
"Otter Tail suggests that PRC-002-1 should be developed on an Interconnection wide basis to ensure consistency and promote reliability of the Bulk-Power System."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards	PRC-002-2 will apply on a continent-wide basis.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
	for the Bulk-Power System (Issued March 16, 2007); Paragraph 1454	
"The Commission requires supplemental information for any Reliability Standard that currently requires a regional reliability organization to fill in missing criteria or procedures. Where important information has not yet been provided to us to enable us to complete our review, we are not in a position to approve or remand those Reliability Standards. Accordingly, we will not approve or remand such Reliability Standards until the ERO submits further information. Until such information is provided, compliance with fill-in-the-blank standards should continue on a voluntary basis, and the Commission considers compliance with such Reliability Standards to be a matter of good utility practice."	Fill-in-the-blank Consideration FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 297.	By addressing recording instead of equipment, the Drafting Team has produced a continent-wide standard to have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.

Project 2007-11 – Disturbance Monitoring

PRC-002-2 – Disturbance Monitoring and Reporting Requirements

Mapping Document for PRC-018-1 to PRC-002-2 and PRC-002-1 to PRC-002-2

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that arise from the inherent differences between regional power systems. PRC-018-1 and PRC-002-1 deal with equipment, PRC-002-2 deals with recording. By specifying data instead of equipment, PRC-002-2 governs the practical capturing of abnormal event data on the BES.

PRC-018-1 Requirements reference PRC-002-1 which requires PRC-018-1 Requirements to be either retired or covered in PRC-002-2.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard **PRC-002 Requirements 1-3**) shall have DMEs installed that meet the following requirements:	**R10.** Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset. 10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1.1. Internal Clocks in DME devices shall be synchronized to **within 2 milliseconds** or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be **retrievable for ten calendar days**.	**R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded. **11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor. **11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2. **11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later. **11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.
Notes: PRC-018-1, Requirement R1 is covered in PRC-002-2, Requirements R10 and R11.	

<table>
<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td colspan="2">PRC-018-1 addresses the equipment used for Disturbance monitoring data recording, PRC-002-2 addresses the recorded data. Technological advances made in the types of equipment used to record power system data have made it more effective to direct PRC-002-2 at the recording, not the equipment. Time synchronization and having the data retrievable for 10 days are general parameters that facilitate data analysis. PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirement R11.</td></tr>
<tr><td>R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization’s installation requirements (reliability standard PRC-002 Requirements 1 through 3).

PRC-002-1
R1. The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:
R1.1. Location, monitoring and recording requirements, including the following:
R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).
R1.1.2. Devices to be monitored</td><td>R1. Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.
1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.
1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns</td></tr>
</table>

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1.Location, monitoring and recording requirements, including the following: R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars. R2.2.Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements. R3. The Regional Reliability Organization shall establish the following installation	connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **3.1** Phase-to-neutral voltage for each phase of each specified BES bus. **3.2** Each phase current and the residual or neutral current for the following BES Elements: **3.2.1** Transformers that have a low-side operating voltage of 100kV or above. **3.2.2** Transmission Lines. **R4.** Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder. **4.2** A minimum recording rate of 16 samples per cycle. **4.3** Trigger settings for at least the following: **4.3.1** Neutral (residual) overcurrent. **4.3.2** Phase undervoltage or overcurrent.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
requirements for **dynamic Disturbance recording**: R3.1. Location, monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following:	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	**5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan. R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **6.1** One phase-to-neutral or positive sequence voltage. **6.2** The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. **6.3** Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. **6.4** Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for wich it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up (GSU) transformer high-side or low-side voltage level. 7.2. The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz

<table>
<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td></td><td>

Rate of change of frequency trigger set at:

Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec
Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec
ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec
Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec

Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meets the following technical specifications: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
9.1 Input sampling rate of at least 960 samples per second.
9.2 Output recording rate of electrical quantities of at least 30 times per second.
</td></tr>
<tr><td colspan="2">Notes: PRC-018-1, Requirement R2 and PRC-002-1 Requirements R1-R3 are covered in PRC-002-2, Requirements R1-R9. PRC-018-1, Requirement R2 references PRC-002-1 Requirements R1-R2. PRC-002-1, Requirements R1-R3 reference equipment installation requirements for FR, SER, and DDR. The technical parameters of PRC-002-2 pertain to the characteristics and content of the recordings that are needed to facilitate event analysis.</td></tr>
<tr><td>R3. The Transmission Owner and Generator Owner shall</td><td>None.</td></tr>
</table>

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker,	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
disconnect status, alarms, etc. R3.8.Monitored electrical quantities, such as voltage, current, etc.	
Notes: PRC-018-1, Requirement R3 is not covered in PRC-002-2. PRC-018-1 Requirement R3 refers to equipment and therefore is not mapped to PRC-002-2 which deals with recorded data and not equipment.	

<table>
<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td>R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization’s requirements (reliability standard PRC-002 Requirement 4).

PRC-002-1

R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following:

4.1. Criteria for events that require the collection of data from DMEs.

4.2. List of entities that must be provided with recorded Disturbance data.

4.3. Timetable for response to data request.

4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool.</td><td>R11. Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

11.1. The recorded data will be provided within 30 calendar days of a request.

11.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request.

11.3. SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2.

11.4. FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later.

11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.</td></tr>
</table>

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
Notes: PRC-018-1, Requirement R4 references PRC-002-1 Requirement R4 which is covered is PRC-002-2, Requirement R11.	
R5. The Transmission Owner and Generator Owner shall each **archive all data** recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	Covered in the Compliance section **1.2 Evidence Retention** The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation: The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years. The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years. The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years. The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years. If a Transmission Owner, Generator Owner, or Responsible Entity (Planning Coordinator or Reliability Coordinator) is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.
Notes: PRC-018-1, Requirement R5 is covered in the PRC-002-2 Compliance section under Evidence Retention.	
R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	**R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the SER, FR or DDR data either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R6.1. Maintenance and testing intervals and their basis. R6.2. Summary of maintenance and testing procedures.	
Notes: PRC-018-1, Requirement R6 is covered in PRC-002-2, Requirement R12. PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R12 deals with the long term availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability.	

Standard PRC-002-1	Proposed Standard PRC-002-2
R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event recording**: R1.1. Location, monitoring and recording requirements, including the following:	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data;

Standard PRC-002-1	Proposed Standard PRC-002-2
R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored	1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified per Requirement R1 and associated with the BES Elements at those BES buses. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
Notes: PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirements R1-R2. (See PRC-018-1, Requirement R3 above for additional information.)	
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1. Location , monitoring and recording requirements, including the following:	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1;

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars.	1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements they own connected to the BES buses identified per Requirement R1: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 3.1 Phase-to-neutral voltage for each phase of each specified line or BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1. Transformers that have a low-side operating voltage of 100kV or above. 3.2.2. Transmission Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include:

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.2. Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements.	• A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault as seen by the fault recorder. **4.2.** A minimum recording rate of 16 samples per cycle. **4.3.** Trigger settings for at least the following: **4.3.1.** Neutral (residual) overcurrent. **4.3.2.** Phase undervoltage or overcurrent.
Notes: PRC-002-1, Requirement R2 is covered in PRC-002-2, Requirements R1, R2, R4, and R5.	
R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**: R3.1. Location , monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

Standard PRC-002-1	Proposed Standard PRC-002-2
consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored	**5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element **5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan. **R6.** Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notifications as identified in

Standard PRC-002-1	Proposed Standard PRC-002-2
element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. **R8.** Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified as per Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz

Standard PRC-002-1	Proposed Standard PRC-002-2
	o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meets the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-002-1, Requirement R3 is covered in PRC-002-2, Requirements R5-R6 and R8-R9.	
R4. The Regional Reliability Organization shall establish requirements for facility owners	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per

Standard PRC-002-1	Proposed Standard PRC-002-2
to **report Disturbance data recorded** by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool, 4.5. Naming of data files in conformance with the IEEE	Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

Standard PRC-002-1	Proposed Standard PRC-002-2
C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	
Notes: PRC-002-1, Requirement R4 is covered in PRC-002-2, Requirement R13.	
R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan.
Notes: PRC-002-1, Requirement R5 is covered in PRC-002-2, Requirements R2, R6-R7.	
R6. The Regional Reliability Organization shall periodically (**at least every five years**) review, update and approve its Regional requirements for Disturbance monitoring and reporting.	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan.
Notes: PRC-002-1, Requirement R6 is covered in PRC-002-2, Requirements R1 and R5.	

Project 2007-11 – Disturbance Monitoring

PRC-002-2 – Disturbance Monitoring and Reporting Requirements

Mapping Document for PRC-018-1 to PRC-002-2 and PRC-002-1 to PRC-002-2

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that arise from the inherent differences between regional power systems. PRC-018-1 and PRC-002-1 deal with equipment, PRC-002-2 deals with recording. By specifying ~~recording~~ data instead of equipment, PRC-002-2 governs the practical capturing of abnormal event data on the BES.

PRC-018-1 Requirements reference PRC-002-1 which requires PRC-018-1 Requirements to be either retired or covered in PRC-002-2.

~~As used herein, the acronym SER is Sequence of Events Recording, the acronym FR is Fault Recording, and the acronym DDR is Dynamic Disturbance Recording.~~

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard **PRC-002 Requirements 1-3**) shall have DMEs installed that meet the following requirements: R1.1. Internal Clocks in DME devices shall be synchronized to **within 2 milliseconds** or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be **retrievable for ten calendar days**.	**R10**. Each Transmission Owner and Generator Owner shall time synchronize all SER and, FR and DDR data for the BES bus buses identified per Requirement R1 and DDR data for the BES Elements identified per Requirement R5 that meet the following:~~to within ± 2 milliseconds of Coordinated Universal Time (UTC), time stamped with or without a local time offset.~~ *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* *10.1 Synchronization to Coordinated Universal Time (UTC), with or without a local time offset.* *10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.* **R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, ~~(C37.111-2013 or later)~~ IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later ~~formatted files~~.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.
Notes: PRC-018-1, Requirement R1 is covered in PRC-002-2, Requirements R10 and R11. PRC-018-1 addresses the equipment used for Disturbance monitoring data recording, PRC-002-2 addresses the recorded data. Technological advances made in the types of equipment used to record power system data have made it more effective to direct PRC-002-2 at the recording, not the equipment. Time synchronization and having the data retrievable for 10 days are general parameters that facilitate data analysis. PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirement R11.	
R2. The Transmission Owner and Generator Owner shall each **install DMEs in accordance with** its Regional Reliability Organization's installation requirements (reliability standard **PRC-002 Requirements 1 through 3**). **PRC-002-1** R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event**	**R1.** Each Transmission Owner ~~shall identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years.~~ [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
recording: R1.1. Location, monitoring and recording requirements, including the following: R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1.Location, monitoring and recording requirements, including the following: R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars. R2.2.Technical requirements, including the following:	90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it~~they~~ owns connected directly to the BES buses identified per Requirement R1 and associated with the BES Elements at those BES buses~~ identified per Requirement R1~~. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] **R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for ~~at~~ the BES Elements it~~they~~ owns connected to the BES buses identified per Requirement R1: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 3.1 Phase-to-neutral voltages for each phase of each specified line or BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1. Transformers that have a low-side operating voltage of 100kV or above. 3.2.2. Transmission ~~l~~Lines.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements. R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**: R3.1. Location, monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored element	R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total~~post-trigger~~ record length of at least 30 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault as seen by the fault recorder. **4.2.** A minimum recording rate of 16 samples per cycle. **4.3.** Trigger settings for at least the following: **4.3.1.** Neutral (residual) overcurrent. **4.3.2.** Phase undervoltage or overcurrent. R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element **5.2.2** One BES Element per 3,000 MW of the Responsible Entity’s historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan. ~~R5. Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable)~~

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	~~shall identify BES Elements for which dynamic disturbance recorder (DDR) data is required, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~ ~~**5.1.** The BES Elements shall include the following:~~ ~~**5.1.1.** Generating resource(s) with:~~ ~~**5.1.1.1.** Gross individual nameplate rating greater than or equal to 500 MVA.~~ ~~**5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA.~~ ~~**5.1.2.** Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines:~~ • ~~Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection or~~ • ~~Transfer Paths in the Western Interconnection Path Rating Catalog or~~ • ~~Voltage stability limited transfer paths or load serving area or~~ • ~~Interfaces between Balancing Authority Areas or~~ • ~~Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC)~~

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	~~5.1.3. Each terminal of a high-voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA on the alternating current (AC) portion of the converter.~~ ~~5.1.4. One or more BES Elements associated with Interconnection Reliability Operating Limits.~~ ~~5.1.5. Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.~~ ~~5.2. The BES Elements shall include a minimum of:~~ ~~5.2.1 One BES Element~~ ~~5.2.2 One additional BES Element per each additional 3,000 MW of its historical peak system Demand.~~ R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5~~, to determine the following electrical quantities~~: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for wich it received notification as identified ~~in~~per Requirement R5~~, to determine the following electrical quantities~~: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up (GSU) transformer high-side or low-side voltage level. 7.2. The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified in~~as per~~ Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers:

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	• Off nominal frequency trigger set at: | | Low | High | o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meets ~~, which conform to~~ the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-018-1, Requirement R2 and PRC-002-1 Requirements R1-R3 are covered in PRC-002-2, Requirements R1-R9. PRC-018-1, Requirement R2 references PRC-002-1 Requirements R1-R2. PRC-002-1, Requirements R1-R3 reference equipment installation requirements for FR, SER, and DDR. The technical parameters of PRC-002-2 pertain to the characteristics and content of the recordings that are needed to facilitate event analysis.	
R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment.	None.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc. R3.8.Monitored electrical quantities, such as voltage, current, etc.	
Notes: PRC-018-1, Requirement R3 is not covered in PRC-002-2. PRC-018-1 Requirement R3 refers to equipment and therefore is not mapped to PRC-002-2 which deals with recorded data and not equipment.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R4. The Transmission Owner and Generator Owner shall each **provide Disturbance data** (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard **PRC-002 Requirement 4**). **PRC-002-1** R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool.	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later. ~~**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~ ~~**11.1.** The recorded data will be provided within 30 calendar days of a request.~~

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	~~11.2. The recorded data will be retrievable for the period of 10 calendar days preceding a request.~~ ~~11.3. SER data will be provided in Comma Separated Value (.CSV) format following Attachment 2.~~ ~~11.4. FR and DDR data will be provided in electronic C37.111, (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files.~~ ~~11.5. Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).~~

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
Notes: PRC-018-1, Requirement R4 references PRC-002-1 Requirement R4 which is covered is PRC-002-2, Requirement R11.	
R5. The Transmission Owner and Generator Owner shall each **archive all data** recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	Covered in the Compliance section **1.2 Evidence Retention** The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation: The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years. The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years. The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years. The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per~~of~~ Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years. The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years. If a Transmission Owner, Generator Owner, or Responsible Entity (Planning Coordinator or Reliability Coordinator) is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.
Notes: PRC-018-1, Requirement R5 is covered in the PRC-002-2 Compliance section under Evidence Retention.	
R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes: R6.1. Maintenance and testing	**R12.** Each Transmission Owner and Generator Owner shall, within 90--calendar days of the discovery of a failure of the SER, ~~and~~ FR or DDR data either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* • ~~, shall r~~Restore the recording capability, or • ~~develop~~Submit a Corrective Action Plan (CAP)~~, to be submitted~~ to the Regional Entity~~,~~ and implement it.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
intervals and their basis. R6.2. Summary of maintenance and testing procedures.	
Notes: PRC-018-1, Requirement R6 is covered in PRC-002-2, Requirement R12. PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R12 deals with the long term availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability.	

Standard PRC-002-1	Proposed Standard PRC-002-2
R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event recording**: R1.1. Location, monitoring and recording requirements, including the following: R1.1.1. Criteria for equipment location (e.g.,	**R1.** Each Transmission Owner shall: ~~identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years.~~ [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within

Standard PRC-002-1	Proposed Standard PRC-002-2
by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored	90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it~~they~~ owns connected directly to the BES buses identified per Requirement R1 and associated with the BES Elements at those BES buses~~ identified per Requirement R1~~. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
Notes: PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirements R1-R2. (See PRC-018-1, Requirement R3 above for additional information.)	
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1. Location , monitoring and recording requirements,	**R1.** Each Transmission Owner shall:~~ identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years.~~ [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault

Standard PRC-002-1	Proposed Standard PRC-002-2
including the following: R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars.	recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for~~at~~ the BES Elements they own connected to the BES buses identified per Requirement R1: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 3.1 Phase-to-neutral voltage~~s~~ for each phase of each specified line or BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1. Transformers that have a low-side operating voltage of 100kV or above. 3.2.2. Transmission ~~l~~Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.2. Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements.	Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total~~post-trigger~~ record length of at least 30 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault as seen by the fault recorder. **4.2.** A minimum recording rate of 16 samples per cycle. **4.3.** Trigger settings for at least the following: **4.3.1.** Neutral (residual) overcurrent. **4.3.2.** Phase undervoltage or overcurrent.
Notes: PRC-002-1, Requirement R2 is covered in PRC-002-2, Requirements R1, R2, R4, and R5.	
R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**: R3.1. Location , monitoring and recording requirements including the following: R3.1.1.Criteria for	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

Standard PRC-002-1	Proposed Standard PRC-002-2
equipment location giving consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored	**5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element **5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan. ~~**R5.** Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder (DDR) data is required, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses~~

Standard PRC-002-1	Proposed Standard PRC-002-2
element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	~~that those Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years.~~ ~~*[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~ ~~**5.1.** The BES Elements shall include the following:~~ ~~**5.1.1.** Generating resource(s) with:~~ ~~**5.1.1.1.** Gross individual nameplate rating greater than or equal to 500 MVA.~~ ~~**5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA.~~ ~~**5.1.2.** Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines:~~ • ~~Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection or~~ • ~~Transfer Paths in the Western Interconnection Path Rating Catalog or~~ • ~~Voltage stability limited transfer paths or load serving area or~~ • ~~Interfaces between Balancing Authority Areas or~~ • ~~Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC)~~ ~~**5.1.3.** Each terminal of a high-voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA on the alternating current (AC) portion of the converter.~~ ~~**5.1.4.** One or more BES Elements associated with Interconnection Reliability~~

Standard PRC-002-1	Proposed Standard PRC-002-2
	~~Operating Limits.~~ ~~5.1.5. Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.~~ ~~5.2. The BES Elements shall include a minimum of:~~ ~~5.2.1 One BES Element~~ ~~5.2.2 One additional BES Element per each additional 3,000 MW of its historical peak system Demand.~~ **R6.** Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notifications as identified in Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. **R8.** Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified as per Requirement R5 shall have continuous data recording and

Standard PRC-002-1	Proposed Standard PRC-002-2
	storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES

Standard PRC-002-1	Proposed Standard PRC-002-2
	Elements identified in Requirement R5 shall have DDR data that meets the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* ~~R9. Each Transmission Owner and Generator Owner shall have DDR data, for the Elements as per Requirement R5, which conform to the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~ 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-002-1, Requirement R3 is covered in PRC-002-2, Requirements R5-R6 and R8-R9.	
R4. The Regional Reliability Organization shall establish requirements for facility owners to **report Disturbance data recorded** by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common

Standard PRC-002-1	Proposed Standard PRC-002-2
Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool, 4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later. ~~**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~ ~~**11.1.** The recorded data will be provided within 30 calendar days of a request.~~ ~~**11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request.~~ ~~**11.3.** SER data will be provided in Comma Separated Value (.CSV) format following Attachment 2.~~ ~~**11.4.** FR and DDR data will be provided in electronic C37.111, (C37.111-2013 or later) IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files.~~ ~~**11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).~~
Notes: PRC-002-1, Requirement R4 is covered in PRC-002-2, Requirement R13.	
R5. The Regional Reliability Organization shall provide its requirements (and any revisions	~~Each Transmission Owner shall identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected~~

Standard PRC-002-1	Proposed Standard PRC-002-2
to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.	~~to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]~~ **R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA.

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. 5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). 5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. 5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). 5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. 5.2 Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: 5.2.1 One BES Element 5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. 5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. 5.4 Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan.

Standard PRC-002-1	Proposed Standard PRC-002-2
	~~**R5.** Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder (DDR) data is required, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~ ~~**5.1.** The BES Elements shall include the following:~~ ~~**5.1.1.** Generating resource(s) with:~~ ~~**5.1.1.1.** Gross individual nameplate rating greater than or equal to 500 MVA.~~ ~~**5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA.~~ ~~**5.1.2.** Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines:~~ ~~Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection or~~ ~~Transfer Paths in the Western Interconnection Path Rating Catalog or~~ ~~Voltage stability limited transfer paths or load serving area or~~ ~~Interfaces between Balancing Authority Areas or~~ ~~Areas of significant congestion, thermal violation history, or relatively low Available~~

Standard PRC-002-1	Proposed Standard PRC-002-2
	~~Transfer Capability (ATC)~~ ~~5.1.3. Each terminal of a high-voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA on the alternating current (AC) portion of the converter.~~ ~~5.1.4. One or more BES Elements associated with Interconnection Reliability Operating Limits.~~ ~~5.1.5. Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.~~ ~~5.2. The BES Elements shall include a minimum of:~~ ~~5.2.1 One BES Element~~ ~~5.2.2 One additional BES Element per each additional 3,000 MW of its historical peak system Demand.~~
Notes: PRC-002-1, Requirement R5 is covered in PRC-002-2, Requirements R2, R6-R7.	
R6. The Regional Reliability Organization shall periodically (**at least every five years**) review, update and approve its Regional requirements for Disturbance monitoring and reporting.	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within

Standard PRC-002-1	Proposed Standard PRC-002-2
	90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. ~~**R1.** Each Transmission Owner shall identify BES buses for which sequence of events recorder (SER) and fault recorder (FR) data is required by using the methodology in PRC-002-2, Attachment 1, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require SER data and/or FR data, and reevaluate the identified buses at least once every five calendar years. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]~~ R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater

Standard PRC-002-1	Proposed Standard PRC-002-2
	than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element **5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan. ~~**R5.** Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder (DDR) data is~~

Standard PRC-002-1	Proposed Standard PRC-002-2
	~~required, notify within 90 calendar days other owners, if any, of Elements connected to those BES buses that those Elements may require DDR data, and reevaluate the identified buses at least once every five calendar years. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*~~ ~~**5.1.** The BES Elements shall include the following:~~ ~~**5.1.1.** Generating resource(s) with:~~ ~~**5.1.1.1.** Gross individual nameplate rating greater than or equal to 500 MVA.~~ ~~**5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000MVA.~~ ~~**5.1.2.** Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines:~~ • ~~Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection or~~ • ~~Transfer Paths in the Western Interconnection Path Rating Catalog or~~ • ~~Voltage stability limited transfer paths or load serving area or~~ • ~~Interfaces between Balancing Authority Areas or~~ • ~~Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC)~~ ~~**5.1.3.** Each terminal of a high-voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA on the alternating~~

Standard PRC-002-1	Proposed Standard PRC-002-2
	~~current (AC) portion of the converter.~~ ~~**5.1.4.** One or more BES Elements associated with Interconnection Reliability Operating Limits.~~ ~~**5.1.5.** Any one BES Element within a major voltage sensitive area with an in-service undervoltage load shedding (UVLS) program.~~ ~~**5.2.** The BES Elements shall include a minimum of:~~ ~~5.2.1 One BES Element~~ ~~5.2.2 One additional BES Element per each additional 3,000 MW of its historical peak system Demand.~~
Notes: PRC-002-1, Requirement R6 is covered in PRC-002-2, Requirements R1 and R5.	

Project 2007-11 Disturbance Monitoring

VRF and VSL Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-002-2 – Disturbance Monitoring and Reporting Requirements.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines.

The Disturbance Monitoring and Reporting Requirements Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria –VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed VRF	**Lower**
NERC VRF Discussion	R1 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 establishes the list of Sequence of Events Recordings and Fault Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for establishing a list of BES bus locations for Sequence of Events Recording and Fault Recording using the selection procedure in Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish the list of BES bus locations for Sequence of Events Recording and Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to establish a list of BES bus locations for Sequence of Events Recording and Fault Recording and to review the list every 5-calendar years. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Lower VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80% but less than 100% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by 10-calendar days or less.
Proposed Moderate VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70% but less than or equal to 80% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.
Proposed High VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60% but less than or equal to 70% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Severe VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by greater than 30-calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R1	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 provides criteria for Sequence of Events Recording which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Sequence of Events Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Sequence of Events Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to establish criteria for Sequence of Events Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 80% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Moderate VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 70% but less than or equal to 80% of the total SER

VRF and VSL Justifications – PRC-002-2, R2	
	data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed High VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 60% but less than or equal to 70% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Severe VSL	Each Transmission or Generator Owner as directed by Requirement R2 for less than or equal to 50% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R3	
Proposed VRF	**Lower**
NERC VRF Discussion	R3 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70% but less than or equal to 80% of the total set of required electrical quantities, which is the product of the total number of monitored BES

VRF and VSL Justifications – PRC-002-2, R3	
	Elements and the number of specified electrical quantities per each Element.
Proposed High VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60% but less than or equal to 57% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R4	
Proposed VRF	**Lower**
NERC VRF Discussion	R4 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recordings selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data that meets more than 80% but less than 100% of the total recording properties as specified in Requirement R4.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data that meets more than 70% but less than or equal to 80% of the total recording properties as specified in Requirement R4.

VRF and VSL Justifications – PRC-002-2, R4	
Proposed High VSL	The Transmission Owner or Generator Owner had FR data that meets more than 60% but less than or equal to 70% of the total recording properties as specified in Requirement R4.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60% of the total recording properties as specified in Requirement R4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-002-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 establishes the list of Dynamic Disturbance Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for identifying BES Elements for Dynamic Disturbance Recording. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to identify BES Elements for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective which identifies BES Elements within specified criteria and to review the list every 5-calendar years. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Responsible Entity identified the Elements for which DDR data is required as directed by Requirement R5 for more than 80% but less than 100% of the required Elements included in Part 5.1. OR

VRF and VSL Justifications – PRC-002-2, R5	
	The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.
Proposed Moderate VSL	The Responsible Entity identified the Elements for which DDR is required as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required Elements included in Part 5.1. OR The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.
Proposed High VSL	The Responsible Entity identified the Elements for which DDR data is requires as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required Elements included in Part 5.1. OR The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.
Proposed Severe VSL	The Responsible Entity identified the Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60% of the required Elements included in Part 5.1. OR

VRF and VSL Justifications – PRC-002-2, R5	
	The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R6	
Proposed Lower VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R6	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R7	
Proposed VRF	**Lower**
NERC VRF Discussion	R7 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R7	
Proposed Lower VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70% but less than or equal to 80% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60% but less than or equal to 70% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R7	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R8	
Proposed VRF	**Lower**
NERC VRF Discussion	R8 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes the need for continuous data recording and storage for Dynamic Disturbance Recordings established in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R6. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R8	
Proposed Lower VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80% but less than 100% of the Elements they own as determined in Requirement R5.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70% but less than or equal to 80% of the Elements they own as determined in Requirement R5.
Proposed High VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 6% but less than or equal to 70% of the Elements they own as determined in Requirement R5.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the Elements they own as determined in Requirement R5.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R8	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R9	
Proposed VRF	**Lower**
NERC VRF Discussion	R9 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement established technical specifications for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish technical specifications for Dynamic Disturbance Recording selected in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective which is to establish technical specifications for Dynamic Disturbance Recording selected in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 80% but less than 100% of the total recording properties as specified in Requirement R9.

VRF and VSL Justifications – PRC-002-2, R9	
Proposed Moderate VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 70% but less than or equal to 80% of the total recording properties as specified in Requirement R9.
Proposed High VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 60% but less than or equal to 70% of the total recording properties as specified in Requirement R9.
Proposed Severe VSL	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60% of the total recording properties as specified in Requirement R9.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3- Consistency among Reliability Standards**

VRF and VSL Justifications – PRC-002-2, R9	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This requirement established technical specifications for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R10	
Proposed VRF	**Lower**
NERC VRF Discussion	R10 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires time synchronization of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations established in R1 and R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failures to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective which is to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90% but less than 100% of the bus

VRF and VSL Justifications – PRC-002-2, R10	
	locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed High VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R10	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R11	
Proposed VRF	**Lower**
NERC VRF Discussion	R11 is administrative in nature and a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 provides criteria around timelines for providing the data and the data format. This is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria on providing Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R11 contains only one objective which is to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data within the specified criteria. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-

VRF and VSL Justifications – PRC-002-2, R11	
	calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% but less than 100% in the proper data format.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% but less than or equal to 90% in the proper data format.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70% but less than or equal to 80% of the requested data. OR

VRF and VSL Justifications – PRC-002-2, R11	
	The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% but less than or equal to 80% in the proper data format.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% in the proper data format.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R11	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R12	
Proposed VRF	**Lower**
NERC VRF Discussion	R12 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 provides criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to follow the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective which is to establish criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action

VRF and VSL Justifications – PRC-002-2, R12	
	Plan to the Regional Entity more than 90-calendar days but less than 100-calendar days after discovery of the failure.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	Guideline 2a: The VSL assignment is for R12 is not binary.

VRF and VSL Justifications – PRC-002-2, R12	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and	Non CIP

VRF and VSL Justifications – PRC-002-2, R12	
implementation should account for their interdependence	

Project 2007-11 Disturbance Monitoring

VRF and VSL Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-002-2 – Disturbance Monitoring and Reporting Requirements.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines.

The Disturbance Monitoring and Reporting Requirements Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria –VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed VRF	**Lower**
NERC VRF Discussion	R1 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 establishes the list of Sequence of Events Recordings and Fault Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for establishing a list of BES bus locations for Sequence of Events Recording and Fault Recording using the selection procedure in Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish the list of BES bus locations for Sequence of Events Recording and Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to establish a list of BES bus locations for Sequence of Events Recording and Fault Recording and to review the list every 5 ~~calendar~~ calendar years. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Lower VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80% but less than 100% of the required BES buses that they own. OR The Transmission Owner evaluated~~assessed~~ the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30 ~~calendar~~ calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by 10 ~~calendar~~ calendar days or less.
Proposed Moderate VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70% but less than or equal to 80% of the required BES buses that they own. OR The Transmission Owner evaluated~~assessed~~ the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30 ~~calendar~~ calendar days and less than or equal to 60 ~~calendar~~ calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by greater than 10 ~~calendar~~ calendar days but less than or equal to 20 ~~calendar~~ calendar days.
Proposed High VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60% but less than or equal to 70% of the required BES buses that they own. OR The Transmission Owner evaluated~~assessed~~ the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60 ~~calendar~~ calendar days and less than or equal to 90 ~~calendar~~ calendar days. OR

VRF and VSL Justifications – PRC-002-2, R1	
	The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by greater than 20 ~~calendar~~ calendar days but less than or equal to 30 ~~calendar~~ calendar days.
Proposed Severe VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60% of the required BES buses that they own. OR The Transmission Owner ~~assessed~~ evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90 ~~calendar~~ calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by greater than 30 ~~calendar~~ calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R1	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 provides criteria for Sequence of Events Recording which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Sequence of Events Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Sequence of Events Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to establish criteria for Sequence of Events Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 80~~75~~% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Moderate VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 7~~5~~0% but less than or equal to 80~~75~~% of the total

VRF and VSL Justifications – PRC-002-2, R2	
	SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed High VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 6~~1~~0% but less than or equal to 7~~5~~0% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Severe VSL	Each Transmission or Generator Owner as directed by Requirement R2 for ~~had from 0% but~~ less than or equal to 5~~1~~0% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R3	
Proposed VRF	**Lower**
NERC VRF Discussion	R3 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80~~75~~% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 7~~5~~0% but less than or equal to 80~~75~~% of the total set of required electrical quantities, which is the product of the total number of monitored BES

VRF and VSL Justifications – PRC-002-2, R3	
	Elements and the number of specified electrical quantities per each Element.
Proposed High VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 6~~1~~0% but less than or equal to 57~~0~~% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers ~~more than 0% but~~ less than or equal to 6~~1~~0% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R4	
Proposed VRF	**Lower**
NERC VRF Discussion	R4 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recordings selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data that meets more than 80~~75~~% but less than 100% of the total recording properties as specified in Requirement R4.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data that meets more than 7~~5~~0% but less than or equal to 80~~75~~% of the total recording properties as specified in Requirement R4.

VRF and VSL Justifications – PRC-002-2, R4	
Proposed High VSL	The Transmission Owner or Generator Owner had FR data that meets more than 6~~1~~0% but less than or equal to 7~~5~~0% of the total recording properties as specified in Requirement R4.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data that meets ~~more than 0% but~~ less than or equal to 6~~1~~0% of the total recording properties as specified in Requirement R4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-002-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 establishes the list of Dynamic Disturbance Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for identifying BES Elements for Dynamic Disturbance Recording. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to identify BES Elements for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective which identifies BES Elements within specified criteria and to review the list every 5 ~~calendar~~ calendar years. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Responsible Entity ~~accurately~~ identified the Elements for which DDR data is required as directed by Requirement R5 for more than 80% but less than 100% of the required Elements included in Part 5.1. OR

VRF and VSL Justifications – PRC-002-2, R5	
	The Responsible Entity ~~assessed~~ identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30 ~~calendar~~ calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10 ~~calendar~~ calendar days or less.
Proposed Moderate VSL	The Responsible Entity ~~accurately~~ identified the Elements for which DDR is required as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required Elements included in Part 5.1. OR The Responsible Entity identified~~assessed~~ the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30 ~~calendar~~ calendar days and less than or equal to 60 ~~calendar~~ calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10 ~~calendar~~ calendar days but less than or equal to 20 ~~calendar~~ calendar days.
Proposed High VSL	The Responsible Entity ~~accurately~~ identified the Elements for which DDR data is requires as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required Elements included in Part 5.1. OR The Responsible Entity identified ~~assessed~~ the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60 ~~calendar~~ calendar days and less than or equal to 90 ~~calendar~~ calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20 ~~calendar~~ calendar days but less than or equal to 30 ~~calendar~~ calendar days.

VRF and VSL Justifications – PRC-002-2, R5	
Proposed Severe VSL	The Responsible Entity ~~accurately~~ identified the Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60% of the required Elements included in Part 5.1. OR The Responsible Entity identified ~~assessed~~ the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90 ~~calendar~~ calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30 ~~calendar~~ calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R5	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.

VRF and VSL Justifications – PRC-002-2, R6	
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R7	
Proposed VRF	**Lower**
NERC VRF Discussion	R7 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.

VRF and VSL Justifications – PRC-002-2, R7	
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80~~75~~% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 7~~5~~0% but less than or equal to 80~~75~~% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60% but less than or equal to 7~~5~~0% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R7	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R8	
Proposed VRF	**Lower**
NERC VRF Discussion	R8 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes the need for continuous data recording and storage for Dynamic Disturbance Recordings established in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.

VRF and VSL Justifications – PRC-002-2, R8	
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80~~75~~% but less than 100% of the Elements they own as determined in Requirement R5.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 7~~5~~0% but less than or equal to 80~~75~~% of the Elements they own as determined in Requirement R5.
Proposed High VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 6~~0~~% but less than or equal to 7~~5~~0% of the Elements they own as determined in Requirement R5.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the Elements they own as determined in Requirement R5.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b:

VRF and VSL Justifications – PRC-002-2, R8	
in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should	Non CIP

VRF and VSL Justifications – PRC-002-2, R8	
account for their interdependence	

VRF and VSL Justifications – PRC-002-2, R9	
Proposed VRF	**Lower**
NERC VRF Discussion	R9 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement established technical specifications for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish technical specifications for Dynamic Disturbance Recording selected in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.

VRF and VSL Justifications – PRC-002-2, R9	
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective which is to establish technical specifications for Dynamic Disturbance Recording selected in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 80~~75~~% but less than 100% of the total recording properties as specified in Requirement R9.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 7~~5~~0% but less than or equal to 80~~75~~% of the total recording properties as specified in Requirement R9.
Proposed High VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 6~~1~~0% but less than or equal to 7~~5~~0% of the total recording properties as specified in Requirement R9.
Proposed Severe VSL	The Transmission Owner or Generator Owner had DDR data that meets ~~more than 1% but~~ less than or equal to 6~~1~~0% of the total recording properties as specified in Requirement R9.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R9	
Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	**Guideline 3- Consistency among Reliability Standards** This requirement established technical specifications for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R10	
Proposed VRF	**Lower**
NERC VRF Discussion	R10 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires time synchronization of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations established in R1 and R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failures to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF and VSL Justifications – PRC-002-2, R10	
	R10 contains only one objective which is to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90% but less than 100% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed High VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2	Guideline 2a: The VSL assignment is for R10 is not binary.

VRF and VSL Justifications – PRC-002-2, R10	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing	Non CIP

VRF and VSL Justifications – PRC-002-2, R10	
interdependent tasks of documentation and implementation should account for their interdependence	

VRF and VSL Justifications – PRC-002-2, R11	
Proposed VRF	**Lower**
NERC VRF Discussion	R11 is administrative in nature and a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 provides criteria around timelines for providing the data and the data format. This is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria on providing Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF

VRF and VSL Justifications – PRC-002-2, R11	
	for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R11 contains only one objective which is to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data within the specified criteria. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30 ~~calendar~~ calendar days but less than 40 ~~calendar~~ calendar days ~~from~~ after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11~~, Part 113.2~~ provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% but less than 100% in the proper data format.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40 ~~calendar~~ calendar days but less than or equal to 50 ~~calendar~~ calendar days after~~from~~ the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11~~, Part 11.2~~ provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% but less than or equal to 90% in the proper data format.

VRF and VSL Justifications – PRC-002-2, R11	
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50 ~~calendar~~ calendar days but less than or equal to 60 ~~calendar~~ calendar days after~~from~~ the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11~~, Part 11.2~~ provided more than 70% but less than or equal to 80% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% but less than or equal to 80% in the proper data format.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60 ~~calendar~~ calendar days ~~from~~ after the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11~~, Part 11.2~~ failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% in the proper data format.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2	Guideline 2a:

VRF and VSL Justifications – PRC-002-2, R11	
Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing	Non CIP

VRF and VSL Justifications – PRC-002-2, R11	
interdependent tasks of documentation and implementation should account for their interdependence	

VRF and VSL Justifications – PRC-002-2, R12	
Proposed VRF	**Lower**
NERC VRF Discussion	R12 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 provides criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to follow the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this

VRF and VSL Justifications – PRC-002-2, R12	
	requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective which is to establish criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90 ~~calendar~~ calendar days but less than 100 ~~calendar~~ calendar days after discovery of the failure.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100 ~~calendar~~ calendar days but less than or equal to 110 ~~calendar~~ calendar days after discovery of the failure.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110 ~~calendar~~ calendar days but less than or equal to 120 ~~calendar~~ calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120 ~~calendar~~ calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

VRF and VSL Justifications – PRC-002-2, R12	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R12 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.

VRF and VSL Justifications – PRC-002-2, R12	
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

Standards Announcement Reminder

Project 2007-11 Disturbance Monitoring
PRC-002-2

Additional Ballot and Non-Binding Poll Now Open through October 22, 2014

Now Available

An additional ballot and for **PRC-002-2 - Disturbance Monitoring and Reporting Requirements** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are now open through **8 p.m. Eastern on Wednesday, October 22, 2014.**

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and non-binding poll of the associated VRFs and VSLs by clicking here.

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballots. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Stephen Crutchfield,

Standards Developer, or at 609-651-9455.

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Standards Announcement

Project 2007-11 Disturbance Monitoring - PRC-002-2

Formal Comment Period Now Open through October 21, 2014

Now Available

A 45-day formal comment period for two of the **Project 2007-11 Disturbance Monitoring PRC-002-2** is open through **8 p.m. Eastern on Tuesday, October 21, 2014.**

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot period for the standards will be conducted **October 10-21, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballots. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Stephen Crutchfield,
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Standards Announcement

Project 2007-11 Disturbance Monitoring - PRC-002-2

Formal Comment Period Now Open through October 21, 2014

Now Available

A 45-day formal comment period for two of the **Project 2007-11 Disturbance Monitoring PRC-002-2** is open through **8 p.m. Eastern on Tuesday, October 21, 2014.**

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot period for the standards will be conducted **October 10-21, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballots. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please cast an abstention.

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Standards Announcement

Project 2007-11 Disturbance Monitoring

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot and for **PRC-002-2 - Disturbance Monitoring and Reporting Requirements** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded **8 p.m. Eastern on Wednesday, October 22, 2014**.

The standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

PRC-002-2	Non-binding Poll
Quorum/Approval	Quorum/Approval
77.69% / 71.38%	76.18% / 67.19%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Stephen Crutchfield, Standards Developer, or at 609-651-9455.

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Ballot Results	
Ballot Name:	Project 2007-11 DM PRC-002-2 Additional Ballot
Ballot Period:	10/10/2014 - 10/22/2014
Ballot Type:	Successive
Total # Votes:	296
Total Ballot Pool:	381
Quorum:	77.69 % The Quorum has been reached
Weighted Segment Vote:	71.38 %
Ballot Results:	The Ballot has Closed

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	101	1	49	0.681	23	0.319	0	7	22
2 - Segment 2	8	0.6	6	0.6	0	0	0	1	1
3 - Segment 3	85	1	36	0.61	23	0.39	0	7	19
4 - Segment 4	29	1	10	0.625	6	0.375	1	7	5
5 - Segment 5	87	1	32	0.552	26	0.448	0	9	20
6 - Segment 6	51	1	24	0.686	11	0.314	0	5	11
7 - Segment 7	4	0.1	0	0	1	0.1	0	0	3
8 - Segment 8	5	0.3	3	0.3	0	0	0	0	2
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.6	6	0.6	0	0	0	1	1
Totals	**381**	**6.8**	**168**	**4.854**	**90**	**1.946**	**1**	**37**	**85**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Hudson Gas & Electric Corp.	Frank Pace		
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	COMMENT RECEIVED
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Negative	COMMENT RECEIVED
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings	Michael Moltane	Affirmative	

	Corp			
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnesota Power, Inc.	Randi K. Nyholm	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman		
1	Montana Dakota Utilities Co.	Teresa Hendrickson		
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	COMMENT RECEIVED
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe Obrien NIPSCO)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL NERC Registerd Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman, Puget Sound Energy)
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Sam Rayburn G&T Inc.	William M Bateman		
1	SaskPower	Wayne Guttormson	Abstain	
				SUPPORTS

1	Seattle City Light	Pawel Krupa	Negative	THIRD PARTY COMMENTS - (See SCL comments)
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	South Texas Electric Cooperative	Renee Davidson		
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	COMMENT RECEIVED
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Amy Casuscelli, Xcel Energy)
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Amy J Miller	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)

3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon /Exelon)
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Hargrave, CPS Energys comments.)
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's)
3	El Paso Electric Company	Rhonda Bryant		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corp)
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Guadalupe Valley Electric Cooperative	Robert B Christmas		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lee County Electric Cooperative	David A Hadzima		
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC

				Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien)
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SCL comments)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe		
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	NO COMMENT RECEIVED
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)

4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	COMMENT RECEIVED
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SCL comments)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Merrell)
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Negative	COMMENT RECEIVED
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	

5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	DTE Energy	Mark Stefaniak	Negative	COMMENT RECEIVED
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon / Chris Scanlon)
5	First Wind	John Robertson	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	Invenergy LLC	Alan Beckham	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	NaturEner USA, LLC	Andrew S Ace		
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPPD Comments)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
				SUPPORTS

5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	THIRD PARTY COMMENTS - (ACES)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Haase, Seattle)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Merrell)
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Liam Noailles	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew

				Gallo)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon / Chris Scanlon)
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Abstain	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Merrell)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway		
				COMMENT

6	Xcel Energy, Inc.	David F Lemmons	Negative	RECEIVED
7	Alcoa, Inc.	Thomas Gianneschi		
7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration LP)
7	Praxair Inc.	David Meade		
7	Valero Services, Inc.	Lee W Morris		
8		Roger C Zaklukiewicz	Affirmative	
8		Debra R Warner		
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

Non-Binding Poll Results

Project 2007-11 Disturbance Monitoring

Ballot Results	
Non-Binding Poll Name:	2007-11 DM Non-Binding Poll October 2014
Poll Period:	10/10/2014 - 10/22/2014
Total # Opinions:	259
Total Ballot Pool:	340
Summary Results:	76.18% of those who registered to participate provided an opinion or an abstention; 67.19% of those who provided an opinion indicated support for the VRFs and VSLs

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (N/A)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	COMMENT RECEIVED
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	

1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman		
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	COMMENT RECEIVED
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	

1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe Obrien)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL NERC Registerd Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman, Puget Sound Energy)
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Sam Rayburn G&T Inc.	William M Bateman		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	

1	South Texas Electric Cooperative	Renee Davidson		
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	COMMENT RECEIVED
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Amy J Miller	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		

3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia		
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Negative	SUPPORTS THIRD PARTY COMMENTS - (Glenn Hargrave, CPS Energy)
3	Detroit Edison Company	Kent Kujala	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	El Paso Electric Company	Rhonda Bryant		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Georgia Transmission Corp)
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Guadalupe Valley Electric Cooperative	Robert B Christmas		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lee County Electric Cooperative	David A Hadzima		

3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien)
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Group Comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	

3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe		
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	City Utilities of Springfield, Missouri	John Allen	Negative	COMMENT RECEIVED
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		

4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Merrell)
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Negative	COMMENT RECEIVED
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	DTE Energy	Mark Stefaniak	Negative	COMMENT RECEIVED
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada		
5	First Wind	John Robertson	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	COMMENT RECEIVED

5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Abstain	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman)

5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Merrell)
5	Tampa Electric Co.	RJames Rocha		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Western Farmers Electric Coop.	Clem Cassmeyer		
6	AEP Marketing	Edward P. Cox	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	

6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	COMMENT RECEIVED
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Abstain	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (John Merrell)
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
7	Alcoa, Inc.	Thomas Gianneschi		

7	Occidental Chemical	Venona Greaff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ingleside Cogeneration LP)
7	Praxair Inc.	David Meade		
8		Debra R Warner		
8		David L Kiguel	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

Individual or group. (51 Responses)
Name (32 Responses)
Organization (32 Responses)
Group Name (19 Responses)
Lead Contact (19 Responses)
Question 1 (43 Responses)
Question 1 Comments (51 Responses)
Question 2 (41 Responses)
Question 2 Comments (51 Responses)
Question 3 (41 Responses)
Question 3 Comments (51 Responses)

Group
Arizona Public Service Company
Janet Smith
Yes
Yes
No
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Yes
Include the Quebec Interconnection in the Introduction Section 4 Applicability. Add to “4.1 The Responsible entity is:” 4.1.4 Quebec Interconnection - Planning Coordinator or Reliability Coordinator As an alternative, define a Responsible Entity for non-specified Interconnection areas. M12 – Remove “of”. Requirement R1, Part 1.2 requires from each Transmission Owner (TO) to notify other owners of BES Elements connected to identified BES buses. It is recommended to revise Part 1.2 to read that each TO provides the list of identified BES buses to their PC / RC who will notify those owners whose BES Elements require SER data and/or FR data. The PC / RC has more authority to maintain a master list of BES buses that require SER and FR data that can provide maximum wide-area coverage. This may avoid TO’s being challenged regarding BES bus selection. Requirement R11, Part 11.3. requires SER data in Comma Separated Value (.CSV) format following Attachment 2 whereas the majority of Disturbance Monitoring Equipment (DME) does not save data in this format. If large data volumes are requested then TO / GO should have their say to the requestor about when they can provide the data in (.CSV) format. Some DME produces records from which SER data would need to be manually extracted, which is very time-consuming. However, the same SER data can be visually seen using COMTRADE viewing software. The standard should not make a file format (such as .CSV) a mandatory requirement. Additionally, Part 11.3 asks to combine SER data from multiple DME devices and from multiple stations. This could be very time consuming and subject to errors.
Individual
Joe O'Brien on behalf of Chirag Patel
NIPSCO

Yes
R3 , GSU transformers are excluded based on the drafting team’s assumption that a fault on the transmission system would be captured by FR data on the Transmission System equipment (line, bus terminals) which is an accurate assumption except for faults on the bus itself. In certain configurations where multiple GSU units terminate into a single Transmission Bus, it is uncertain if this could indeed be calculated as stated by deciphering the contribution from various units. As stated in the current draft of PRC-002-2 Pg 39 of 46 top of page, current calculations would not be required from the GSU terminals of each generator since they can be readily calculated if needed, which is not an accurate statement in all configurations. This leaves what could be a substantial gap for bus faults or for configurations where multiple units of different sizes terminate on separate terminals of the transmission bus. Example would be a large Transmission Substation with a breaker and half configuration with 4 GSU units all terminating on separate terminals into the transmission bus. These units could be of different size and fuel source (Coal units, gas turbines, etc) all terminating to the same transmission bus leaving a substantial gap in FR recording data since the only thing that will be captured is the aggregate of the generation through calculation for external faults, and only simulated data for bus faults. Generators are typically the most significant contributor to transient and sub-transient local fault current at or near larger generation facilities, and also the most susceptible cause of cascading which may result from instability following a system disturbance. Therefore, this requirement would not provide the required data to decipher problem areas on specific generators that may have truly been the root cause without extensive simulation of data using, what would then be, calculated empirical data, not real captured data. This exclusion only appears beneficial for external close in faults and configurations where either a single GSU is connected to the transmission system or a single collector bus with an aggregate GSU source from many of the same units are connected to a Transmission Bus. For the purposes of the standard, exclusions should not be granted to generation terminals since it would result in a discriminatory practice. All significant sources of fault current on an applicable BES Transmission Bus should be deemed equally important for capturing FR data and the only exclusions should be to terminals or elements which only provide load.
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
Within the Rationale for Requirement R10, it is unclear which device the drafting team intends to be synchronized to within +/- 2 milliseconds of UTC. Although the last paragraph of the Rationale for R10 states that the “accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment”, the following sentence states that “the equipment used to measure the electrical quantities must be synchronized to +/-2 ms accuracy”. This creates confusion in terms of whether the accuracy requirement applies to the clock used for synchronizing the monitoring equipment, to the monitoring equipment itself, or to both. Recommend additional clarification be included within the Rationale for R10 or else to R10.2 to prevent further confusion.
Yes
As currently written, LES is having difficulty following Attachment 1 due to the confusing references. At a minimum, recommend clarification be added as to what “list” each step in the attachment is referring to, considering that the “list” may change throughout the steps. For example, in Step 3, does the “list” in the second sentence refer to the list created in the first sentence, or is it referring to the “list” created in Step 2? Or should the second sentence in Step 3 be moved to Step 2? Without additional clarification, it is difficult for an entity to determine how to proceed through the steps in the attachment, especially Step 7.
Individual
Amy Casuscelli
Xcel Energy

Yes
In response to Xcel Energy’s comment in the previous ballot, the drafting team states that changes were made in Step 7 and 8 to recognize that requiring close busses have date recording equipment would not provide significant value. However, a review of these steps in the redline document does not show that changes were made to address this issue. The drafting team did add language in the Rationale box under Requirement 3 addressing busses serving only generators but it is not clear how this rationale statement is made part of the requirements. Because of the perceived conflict in the rationale compared to the requirement, Xcel Energy is voting negative on the standard. We believe that the rationale statement is correct but the change has not been implemented in the requirement and associated calculation. Please correct this oversight. Thank you for your effort on this issue.
Group
Seattle City Light
Paul Haase
Yes
Seattle City Light does not support this Standard as structured or as written. We believe siting of monitoring equipment should be coordinated at a higher (regional or sub-regional) level to promote the most cost-effective installations. We do not believe the proposed level of technical detail (which changes constantly as technologies improve and change) is appropriate to a federal Standard (which is very difficult and slow to update and change). Finally, if a Standard something like the proposed approach is necessary, we find the 1500 MVA fault duty values to be low by a factor of 3 or 4, if not perhaps by a factor of 10.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
Yes
Individual
David Jendras
Ameren
Yes
We believe that Requirement R5 as written would require the addition of about a dozen additional PMUs to our system. For us this number would be much more manageable than the number called for in earlier drafts of this standard. Because this draft targets monitoring generators of significant size, disturbance monitors can potentially generate disturbance data useful in refining dynamic model representations for this equipment over time.
Yes
Based on our experience it would be difficult to keep communications network delays within the +/- 2 millisecond window. In our opinion, a reasonable approach would be to limit this requirement to the synchronizing clock equipment as shown in the modified draft standard, which would be feasible and sufficient.
Yes
To help assure the ability to meet the 90-day time limit for Requirement R12, we believe that it may be necessary to have at least one spare of each model of PMU installed on the system on hand for use in replacing a failed unit in a timely manner.
Individual
David Thorne

Pepco Holdings Inc
Yes
Yes
No
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Yes
No
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration L.P. (ICLP) agrees with the extensive and consistent negative response from a number of respondents to the previous posting regarding DDR. We (and they) believe that R5 will unnecessarily over-drive the deployment of phase measurement units (PMUs). PMUs are a fast improving technology and the DDR owners will quickly find that their equipment is obsolescent. We can agree that PMUs must be deployed in critical areas regardless, but do not see the same sense of urgency for locations of lesser BES importance. Specifically as a GO, ICLP agrees with the criteria developed in PRC-023 and CIP-002 to establish critical generation facilities. In our view, this would be those whose aggregate output exceeds 1500 MVA and attach to the BES at 200 kV or more. (Of course, there must be special consideration for facilities that are part of a SOL/IROL, but those locations are already captured in R5.) After the industry gains familiarity with PMU technology, further integration at lower capacities and voltages may be considered. By then, there will be far more exciting and useful options available – and will no doubt prove to be more useful to investigators trying to consolidate data related to a wide-area outage.
Yes
Individual
Mark Wilson
Independent Electricity System Operator
Yes
We agree with the changes made to the BES Elements requiring data listed in R5, but have concerns over the other changes to R5 (and R1). Please see our comments under Q3.
Yes
Yes
We generally agree with all the proposed changes. However, the addition of the phrase “and implement the reevaluated list of BES buses as per the Implementation Plan” to Part 1.3 and the phrase “and implement the reevaluated list of BES Elements as per the Implementation Plan” to Part 5.4 is unnecessary which makes the requirement out of date over time. The implementation timeframe should be stipulated in the Implementation Plan, not in the requirements. We suggest the SDT to make this change, which can be regarded as not having material impact to the intent of the

concerned requirements and hence may not require another round of successive balloting if this draft receives 2/3 majority support at the ballot.
Individual
Thomas Foltz
American Electric Power
Yes
Yes
Yes
AEP recommends modifying R2-R4 and R6-R11 to clearly exempt data lost due to an equipment failure properly identified per R12. Our concern on this matter has led, in part, to our decision to vote negative on the standard. R3: The Application Guide implies that GSU leads are not considered lines for this standard. The requirement should be revised to clearly indicate this. Similarly, station service or reserve transformers should likewise be explicitly excluded. Our concern on this matter has led, in part, to our decision to vote negative on the standard. As stated in our previous comments, AEP recommends modifying R3 so that only three of the four currents are required to be recorded. Since the fourth current can be calculated by the other three, there is no reliability impact for recording only three currents. The drafting team responded by saying “The Rationale Box for Requirement R3 explains the need for the three phase currents and the residual or neutral current”, however it is not necessary to monitor all these quantities to provide the data mandated by R3. It is clear from the rationale section for R3 that GSU transformers are excluded from the requirement. However, R3 states “Each TO *and GO* shall have FR data...for the BES Elements it owns connected to the BES buses…”. The requirement should be revised to align with the exclusion provided stated in the rationale section. R12: We see no reliability benefit in sending all CAP’s to the Regional Entity, and recommend revising it in consideration of Paragraph 81. Rather, it should be acceptable to only require the TO/GO to develop and execute a CAP and to make this information available to the RE within 30 calendar days of a request. R2: We believe that it is clear that the TO/GO must have SER data for circuit breaker position as it related to the following BES elements connected to a BES bus; BES Transmission Lines, BES Transformers and BES Generator feeds. Does this Requirement also apply to circuit breakers/circuit switchers that serve BES shunt capacitors/reactors?
Individual
John Pearson/Matt Goldberg
ISO New England
No
By definition, SOLs do not impact other areas and, for that reason, it would be more appropriate to leave the determination regarding monitoring of SOLs up to the Responsible Entity. Accordingly, Requirement 5.1.2 should be deleted. However, if Requirement 5.1.2 is not deleted, then the words “Any one” in Requirement 5.1.2 should be replaced with the words “One or more.” This will make it clear that the Responsible Entity is required to select one (or more) BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL) and will also make Requirement 5.1.2 consistent with Requirement 5.1.4, which already uses the words “One or more.” In Requirement 5.1.3, the word “circuit” should be replaced with the word “interconnection” or the word “facility” to ensure that back-to-back HVDC is monitored; these types of interconnections are being planned for New England and the word “circuit” may create confusion about monitoring them. Also, to make Requirement 5.1.3 clearer, the words “…for which the Responsible Entity is responsible” should be added at the end of the sentence. The words “Any one” should also be replaced with the words “One or more” in Requirement 5.1.5. Again, this will make it clear that the Responsible Entity is required to select one (or more) BES Element within a major voltage sensitive area as defined by an area with an in-service UVLS program, and will make the requirement consistent with Requirement 5.1.4.
Yes
Yes

The triggers described in the first two bullets of Requirement 8.2 should be clarified to include the duration that the Standard Drafting Team based them on. Otherwise, the data produced may be inconsistent across interconnections and may be subject to different interpretations. Requirement 11.3 should be deleted because providing the data in formats other than ASCII Comma Separated Value (.CSV) should be allowed. In other words, the requirement should not prescribe a data format.
Individual
Manon Paquet
Hydro-Quebec Production
Yes
Yes
No
Individual
Chris Scanlon
Exelon Companies
No
Regional DME criteria in RF was 1000 MVA, Exelon thinks the threshold in R5 should be raised to the 1000 MVA per the RF Criteria.
Requirement R7.1: For clarity consider replacing the first comma with “or” to read “One phase-to-neutral or phase-to-phase or positive sequence voltage……” R7.2: Similar comment - for clarity, consider rewording to replace the commas with “or” to read “The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7.1 or phase current(s) for any phase-to-phase voltages or positive sequence current.” R9.3 requires an output recording rate of at least 30 times per second while the existing NPCC and RFC-CRITERIA-PRC-002-01 requires a recording rate of 6 times per second. Some of the equipment in question was installed in the last several years to meet the RF stadnard/criteria. To meet this new requirement legacy devices will need to be either upgraded or replaced because the higher recording rate will mean they cannot hold a continuous 10 day record. Relaxing the recording output rate to the existing 6 times per second would be sufficient to allow these devices to be compliant with the requirement. The implementation plan for PRC-002-2 includes the following installation requirement for newly-added buses from the re-evaluation process: “Entities shall be 100 percent compliant with a re-evaluated assessed list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated of the list.” The requirement for a 3-yr compliance period will conflict with previously scheduled and planned outage / maintenance cycles . Modifying outage cycles with the time necessary to specify and acquire new equipment will be disruptive. In place of a prescriptive cycle requirement, we propose the requirement be changed to say, Entities shall submit a plan to be 100% compliant with a re-evaluated list from requirements R1 and R5 within 180 days following notification by the TO/Responsible Entity. This plan should include expected completion date(s) justified by outage constraints, equipment lead times and availability. R12 and/or M12 should be modified. We will be using microprocessor relays that also provide protection for SER, FR, and DDR functions. Microprocessor relays that provide protection functions are not allowed to be out of service following a failure for anywhere near 90 days. In addition, we have these relays on all 200kV and above lines. Thus, the failure of one device is not too important from a DME standpoint. Given all this, this requirement is unnecessary for an entity using microprocessor relays as described. We propose that M12 states that protective relaying also used as DME is excluded from this requirement since it is inherent that it will be fixed in less than 90 days. Keeping data to show that relay failures were repaired in less than 90 days is an unnecessary administratve burden and does not contribute to reliable operations. The standard should recognize the varying technologies are used to perform this function and not create administrative burdens. An alternative might be to change the measure to state that if an event occurs that requires RRO or NERC investigation sufficient data was made available to NERC or the RRO to support the event investigation. This will eliminate the need to keep records proving that equipment was fixed in a timely manner.

Individual
John Allen
City Utilities of Springfield, Missouri
No
City Utilities of Springfield, Missouri supports the comments submitted by the SPP Standards Review Group.
No
City Utilities of Springfield, Missouri supports the comments submitted by the SPP Standards Review Group.
Yes
City Utilities of Springfield, Missouri supports the comments submitted by the SPP Standards Review Group and the following additional suggestions: Regarding R1 and Attachment 1: We continue to believe the Attachment 1 fault MVA threshold established in R1 to identify potential buses from which to pick locations for FR (and SER) data is too low. All of the BES buses on our system have fault MVA above the 1500 MVA threshold and no reduction to the number of buses on our list occurs by application of the steps outlined in Attachment 1. Given the size of our utility, it seems odd to us that all of our buses are considered “key” to the BES. Regarding R3: We continue to believe it is not necessary to be able to determine the electrical quantities associated with every element connected to a bus for a fault on one element of the bus. Rather, we believe that if devices are present to capture sufficient data necessary to determine the required quantities associated with the “faulted” element, that is sufficient for fault analysis. We believe it is sufficient for an entity to be able to determine fault location, fault type, cause of relay operation and the currents and voltages required by this proposed Standard associated with the faulted element for the purposes of Fault Recording. This seems to meet the intent voiced in the “Rationale for R3”. Please clarify the purpose of requiring electrical quantities be determined for all elements connected to a bus for a fault on any element of that bus if the required quantities associated with the faulted element can be determined. Also, it seems to us that comments regarding determining correct operations of the protection system within the proposed Standard and guidelines document are out of scope for this Standard and are already covered in other NERC Standards, PRC-004 specifically. Regarding R4: We appreciate the SDT revising the total record length in the first bullet under R4.1 from at least 32 cycles to at least 30 cycles. Regarding R10: We appreciate the SDT’s clarification that the time synchronization pertains to the device clock.
Group
ACES Standards Collaborators
Brian Van Gheem
No
We appreciate the DMSDT’s decision to incorporate more explanation in the rationales of this standard based on its extensive outreach to event analysis subject matter experts. We feel that the DMSDT has taken steps to answer some of the concerns regarding the requirements that seek to find “why” an event occurred. However, we continue to disagree that the standard addresses the “what” of data collection and not the “how” the data is collected. How is an entity going to provide data if it does not have the equipment present to collect it? The fundamental principles of this standard seem flawed when the purpose of this standard is to have “adequate data available to facilitate analysis of BES Disturbances.” We feel NERC can communicate the intent of collecting data for the purposes of explaining why an event occurred through a Reliability Guideline instead of an enforceable standard. NERC already has enforceable standards on reporting events, monitoring system conditions, and identifying entity-to-entity data specifications. The data collected and available through these existing standards are through “proactive” devices and applications, which entities then generally archive for historical and training purposes. We believe sufficient data is already available, as evident with the data available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California Outages. As stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, “PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP).” The resulting report identified no additional standards because of this event. By continuing to pursue an

enforceable standard to address outdated recommendations from the 2003 Blackout in the Northeast does not seem cost effective for both industry and NERC. A Reliability Guideline will not deter industry from installing additional or maintaining existing event recording devices. However, it gives industry an opportunity to balance the risk of not installing or maintaining such devices with pursing advancements in technologies with the more "proactive" and "preventable" devices and initiatives.
No
We feel that NERC can communicate technical specifications for data collection explaining why an event occurred through a Reliability Guideline. As stated on the NERC web site, "reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability." We feel NERC and industry jointly pursuing a Reliability Guideline on this topic collaboratively would be better use of time and resources.
Yes
(1) When compared to other enforceable standards, the number of requirements identified in this standard is greater than the number of requirements currently enforceable for standards related to event reporting and entity-to-entity data specifications. We continue to believe that many of these requirements are unnecessary and fall under Paragraph 81 Criteria B. However, if the DMSDT feels that such information is "essential to expeditious and efficient data analysis," we believe these technical specifications could be included in a technical guideline or Compliance Section attached to this standard. Requirements R4 and R9 regarding data sampling and requirement R10 regarding time synchronization are just three of the numerous specifications listed in this standard. Requirement R11 identifies the data format and nomenclature expected for entities to follow. Even the current requirements associated with the Disturbance Control Standard, NERC Standard BAL-002-1, do not identify the data format as a requirement. Moreover, the individual parts of requirement R11 cite various IEEE standards and specifications, references the DMSDT could identify as footnotes. Many other SDTs, such as the one that developed NERC Standard PRC-023-2, relocated their technical information to other appropriate areas or documents. Likewise, requirement R8 identifies system conditions that are necessary to trigger the initiation of data recording if continuous data recording is unavailable. We believe the DMSDT should move these technical specifications to an appendix of the standard and not identify them as enforceable requirements. (2) We concur with the DMSDT that the term "BES buses" provides confusion. We believe requirements R1.1 and R1.3 should be rewritten to "BES Elements connected to a BES bus" to alleviate any further confusion. (3) We believe the term "and/or" listed in Requirement R1.2 could provide confusion. We recommend change the requirement to read, "Notify, within 90-calendar days, other owners of BES buses identified within R1.1 that require SER data and FR data." (4) We believe the DMSDT should remove references to the Implementation Plan, as embedded directly within the requirement text, and incorporated this information into an "Effective Date" entry listed under the Introduction (Section A) of this standard. Such references include R1.3 and R5.4. (5) We believe the DMSDT should remove the reference to "local time offset" in Requirement R10.1. Its reference to the time listed in SER and FR data and their synchronization to Coordinated Universal Time (UTC) is an unnecessary addition to the text of this requirement. (6) Requirement R11 identifies that entities are required to provide all SER and FR data, upon request, to the Regional Entity and NERC. NERC already defines this mechanism in Section 1600 of the NERC Rules of Procedures. We suggest the DMSDT remove all references to the Regional Entity and NERC from this requirement. (7) Requirement R12 states that an entity should first submit a Corrective Action Plan (CAP) to its Regional Entity and then implement the plan. We recommend the DMSDT follow a similar approach taken in NERC Standard PRC-004-3, where the entity is first required to develop a CAP and then required to implement and provide updates until the plan is completed. Both industry and NERC have already reviewed this language and the standard is currently on file with FERC. (8) The term "Responsible Entity" is already a defined term in Appendix 2 of the NERC Rules of Procedures. We recommend the DMSDT revise all references to Responsible Entity within this standard accordingly. (9) We continue to disagree with the DMSDT that this standard addresses the "what" of data collected and not "how" the data is collected. The costs of installing new equipment for the purposes of disturbance monitoring could be significant for some of our members. Moreover, industry has already benefitted from the DOE grants to install PMUs and would continue to benefit from these types of financial incentives for continual situational awareness. The DMSDT continues to rebut our previously submitted comments with references to the 2003 Blackout in the Northeast. However, it

was through these financial incentives, that sufficient data was available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California Outages. As stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, “PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP).” Moreover, the resulting report identified that no additional standards were necessary because of this event. We suggest NERC should develop a Reliability Guideline on this topic instead of a standard, as we do not see the cost benefit or justification to allocate resources for an issue that is not a high priority for reliability. (10) Thank you for the opportunity to comment.
Individual
Alshare Hughes
Luminant Generation Company, LLC
Yes
Yes
Luminant is specifically concerned about the administrative requirements in the standard related to reporting formats. Luminant does not disagree with the desire or benefit of standardized reporting, however, we believe specific data and reporting formats do not belong in the standard requirements. The ERO already has the authority to request data and reports in specific forms or formats. (1) Requirement R11, subsections 11.3, 11.4 and 11.5 includes prescriptive details regarding data recording and reporting. The goal of the standards development process is to develop Results Based Standards. We reiterate our concern that these items are completely administrative in nature and are not results based. An entity could make a typo in formatting or when naming a file and be non-compliant with the requirement. These requirements should be removed from the standard or relocated to reference documents. (2) Requirement R11, subsections 11.4 and 11.5 reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. Inclusion in a reference document seems to provide a better location to document specific details on requested data and can provide a more effective mechanism for revising these details at a later date in regards to the data reporting. The requesting agency has the right to ask for data in any prescribed format they desire, but this should not be identified in the standard. (3) Requirement R11, subsection 11.4 specifically references “IEEE C37.111-2013”. We reiterate our previously submitted comment on the version specification. The SDT response focused on conversion software. Some older DFRs that effectively capture the needed data may not meet this requirement for the “2013”. Software updates may not always be reasonably accomplished with equipment, service contracts or other factors. This 2013 mandate is administrative in nature and does not contributed to a results based standard nor improve BES reliability. This version requirement should be revised to allow for any versions that the entity has access to that supports the recording and report requirements.
Group
Dominion
Mike Garton
No
See comments in Question #3.
No
See comments in Question #3.
Yes
Project 2007-11 Disturbance Monitoring was initiated to replace the existing fill-in-the-blank Reliability Standard PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements with a more comprehensive standard. Project 2007-11 began in March 2007 with the objective to develop a continent-wide Disturbance Monitoring (DM) Reliability Standard. One Regional Entity (NPCC) developed a DM Regional Reliability Standard (FERC approved) in absence of a continent-

wide standard. Dominion does not support this Reliability Standard and recommends that the SDT consider the following: 1. Is a continent-wide DM Reliability Standard necessary? With the exception of NPCC, no other Regional Entity has a Regional Reliability Standard for DM. Perhaps existing regional guidance/practices employed since 2007 are sufficient. There has been many new installations of DM equipment since the Version 0 fill in the blank standard was remanded back to NERC. Perhaps a suitable alternative to a standard would be for NERC to issue guidance similar to guidance that was issued for cold weather preparedness in lieu of a standard. 2. Duplicity and/or differences between Regional Reliability Standard and continent-wide Reliability Standard. Specifically: Dominion remains concerned that PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2014, NPCC applicable entities are three years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Once approved, NPCC applicable entities must comply with both PRC-002-2 and PRC-002-NPCC-01, requiring those entities to review and determine the more stringent requirements between the regional and continent-wide standards. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01). 3. Equipment installation may be necessary to obtain the data specified in the Reliability Standard. Considering the criteria, some merchant generators, but not all, will incur costs that are not recoverable to install the equipment. This results in an unfair competitive advantage for some market participants. 4. Please consider the following items for consistency: M1 needs to be updated to include Parts 1.1, 1.2, and 1.3, similar to how M4 and M5 included the Parts. R11.1 should be reworded to include the word “consecutive” to read “period of 10 consecutive calendar days” and change test from “the data was recorded” to “the data was requested.”
Individual
Anthony Jablonski
RelliabilityFirst
No
ReliabilityFirst votes in the Affirmative and believes the standard helps ensure that adequate data is available to facilitate analysis of Bulk Electric System (BES) Disturbances. This standard also removes the “fill in the blank” aspects of the old PRC-002 and PRC-018 standards. ReliabilityFirst offers the following comments for consideration: 1. Requirement R5, Part 5.3 - Requirement R5, Part 5.3 requires notification within 90- calendar days of completion of Part 5.1, but then goes on to state “when requested”. ReliabilityFirst questions whether the intent is “within 90-calendar days” or “when requested”. ReliabilityFirst believes the SDT should choose one or the other. 2. Requirement R5, Part 5.4 - Requirement R5, Part 5.4 references an “Implementation Plan” and it is unclear to ReliabilityFirst how this will be enforced. The Implementation Plan only speaks to the initial identification of buses and does not address the re-evaluation of the list. Furthermore, a NERC Reliability Standard should not have requirements that reference documents which are outside of the standard. ReliabilityFirst suggests this reference to Implementation Plan be removed from Part 5.4.
Yes
ReliabilityFirst votes in the Affirmative and believes the standard helps ensure that adequate data is available to facilitate analysis of Bulk Electric System (BES) Disturbances. This standard also removes the “fill in the blank” aspects of the old PRC-002 and PRC-018 standards. ReliabilityFirst offers the following comments for consideration: 1. Requirement R1, Part 1.3 - Requirement R1, Part 1.3 references an “Implementation Plan” and it is unclear to ReliabilityFirst how this will be enforced. The posted PRC-00202 Implementation Plan only speaks to the initial identification of buses and does not address the re-evaluation of the list. Furthermore, a NERC Reliability Standard should not have requirements which reference documents which are outside of the standard. ReliabilityFirst suggests this reference to Implementation Plan be removed from Part 1.3.
Individual
Jamison Cawley

Nebraska Public Power District
No
R5 5.2 states “5.2 Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: 5.2.1 One BES Element; and 5.2.2 One BES Element per 3,000 MW of the Responsible Entity’s historical simultaneous peak System Demand.” Please explain how “Ensure a minimum DDR coverage” relates to the implementation plan where 100% compliance is required within 6 months of approvals. What is R5.2 acceptable evidence after 6 months? Is this just an identification requirement that the planning coordinator must provide in this 6 month time frame? This question arises because “Ensure” is used instead of “Identify”. R5 question: For example, a utility has two DDRs on its system because it has two generating resources greater than 500 MVA at two separate locations. If this utility also has 3,030 MW peak demand will the two DDRs on its system satisfy R5.2? In addition to these comments, we also support the comments provided by SPP.
No
We support the comments provided by SPP.
R11 requires “Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.” It appears a chattering contact could easily fill up an SER or FR device in a matter of minutes or less if it occurs near an event. It is difficult to control or address these issues but they could be a serious impact to the 10 calendar day requirement. Is there a way to minimize this requirement such that event triggers or SERs don’t need to be decreased to help ensure data has less chance of being overwritten? Some microprocessor relays only hold 12 event records so this is more difficult to guarantee data is available this long. In addition it is possible to have more than 12 operations within 10 days during stormy periods. It would seem this case would not allow the data to be available in a relay for the required time. This requirement could force utilities to eliminate many older microprocessor relays on the system that have limited programming and memory capability where the risk for non-compliance could be too great. If this happens then the assertion that many of devices are already on the system that meet the recording requirements is not a generally true statement. Consider removal of this 11.1 requirement since this capability is not entirely under the control of the owner. M1 question: Do we need to just show we sent a notification within 90 days to other owners of BES elements for an identified bus or also show a response? Just showing we sent the notification in good faith is preferred. R12 question: The implementation plan states we have 9 months after approval to be 100% compliant for R12. Does this mean we need to be compliant for R12 with elements as they become compliant in R2, 3, 4, 6, 7, 8, 9, 10 and 11 over the implementation time frame? For example, since it could be 4 years and only 50% of elements and their recording capabilities will be compliant how is requirement R12 applied to locations not yet compliant? R4 states: “Trigger settings for at least the following: 4.3.1 Neutral (residual) overcurrent. 4.3.2 Phase undervoltage or overcurrent.” Is it possible to allow additional “OR” statements for 4.3.2? Many relays used for FR will use the phase impedance zone reaches to trigger records. This can clearly define the reach for data to be triggered where defining an under voltage or overcurrent may be more difficult to control the reach. There is some concern with overwriting data in the relays with settings that are less intuitive for controlling how often a device may trigger. We strongly recommend allowing phase distance reaches as trigger points. In past comments it may have appeared to be suggested as overcurrent or distance be included but what was meant was to have both as part of an OR statement. Suggestion: Phase under voltage or overcurrent or distance reach. R12 states “Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.” Should the RE or regional entity be listed in the Applicability section? For some registered entities the Planning Coordinator and the Regional Entity may not be the same. In addition to these comments, we also support the comments submitted by SPP.
Individual
Gul Khan
Oncor Electric Delivery LLC
No
In the rationale for R5 it states “For an interconnection between two TO’s, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.” We do not think the Responsibility Entity should determine if the TO or GO will provide the data. Oncor recommends that if there is an

interconnection between a TO and GO at the same BES location then the requirement should fall upon the GO. However if the TO has the data then the GO can contract with the TO for the data as mentioned in the rationale for R7 below: “Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.”
Yes
Yes
We recommend the following language from the R7 to be used in R3 “Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.” As currently written the rationale in R3 places the burden on the TO when the GO should be held responsible. It is not a "given" that the TO FR is already monitoring GO generator breakers due to the legal deregulation splitting of asset ownership and monitoring isolation between TO/GO interfaces. In regards to R2 and R11.3 we recommend a similar provision for Legacy devices be provided as done in R8. We recommend the following verbiage be added: “If the FR equipment was installed prior to the effective date of this standard and is not capable of SER recording, Breaker position must be monitored by a digital element in the FR.” Oncor recommends the following verbiage be added after the last sentence in the Guideline for Requirement R6 and R7: “The R6.3 and R7.3 assumption is that there is a balanced 3 phase system so calculating 3 phase power based on single phase voltage and current quantities is acceptable”
Individual
Gul Khan
Oncor Electric Delivery LLC
No
In the rationale for R5 it states “For an interconnection between two TO’s, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.” We do not think the Responsibility Entity should determine if the TO or GO will provide the data. Oncor recommends that if there is an interconnection between a TO and GO at the same BES location then the requirement should fall upon the GO. However if the TO has the data then the GO can contract with the TO for the data as mentioned in the rationale for R7 below: “Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.”
Yes
Yes
We recommend the following language from the R7 to be used in R3 “Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.” As currently written the rationale in R3 places the burden on the TO when the GO should be held responsible. It is not a "given" that the TO FR is already monitoring GO generator breakers due to the legal deregulation splitting of asset ownership and monitoring isolation between TO/GO interfaces. In regards to R2 and R11.3 we recommend a similar provision for Legacy devices be provided as done in R8. We recommend the following verbiage be added: “If the FR equipment was installed prior to the effective date of this standard and is not capable of SER recording, Breaker position must be monitored by a digital element in the FR.” Oncor recommends the following verbiage be added after the last sentence in the Guideline for Requirement R6 and R7: “The R6.3 and R7.3 assumption is that there is a balanced 3 phase system so calculating 3 phase power based on single phase voltage and current quantities is acceptable”
Individual
Jonathan Meyer
Idaho Power
Yes

Yes
No
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
Yes
1) Requirement R12: Texas Reliability Entity, Inc. (Texas RE) reiterates the concern raised during the previous ballot period that the Regional Entity is the appropriate entity to receive a TO or GO's Corrective Action Plan (CAP) as written in this requirement. Based on the language in the "Rationale for Functional Entities," it appears that either the Planning Coordinator (PC) or the Reliability Coordinator (RC) should be the recipient of the CAP. The Rationale for Functional Entities states that the "The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required." Since the PC or RC is responsible for determining which BES Element data is needed, then they arguably need to know when there is a failure of the recording capability for that data and what the CAP is to restore the recording capability. The PC or the RC are in a better position to evaluate whether a CAP has been implemented. Therefore, submitting the CAP to the PC or RC is more appropriate than submitting the CAP to the Regional Entity as it will likely enhance reliability. Texas RE recommends the SDT change the second bullet under Requirement R12 from the "Regional Entity" to the "Responsible Entity." 2) Requirement R1 VSLs: The language within the first "OR" of the Lower VSL states the TO was late by 30 calendar days or less for Parts R1.1 and 1.3. Texas RE has two concerns regarding the language: A) Texas RE is not clear on what the VSL criteria of 30, 60, 90 or more than 90 calendar days is measuring against. Would the SDT please explain what the TO would be late for since Requirement R1.1 has no time criteria? B) Texas RE requests the SDT consider whether the VSLs for re-evaluating all BES buses at least once every five calendar years for Part R1.3 is appropriate. For an evaluation that is deemed sufficient to be performed at a frequency of every five years, it would seem that being late by 30, 60, 90 or 90-plus days might not be the correct timeframe for assessing the severity of a violation. Texas RE suggests assigning criteria on quarters. So that a Lower VSL would be late by one quarter, Moderate VSL would be late by two quarters, High VSL would be late by three quarters and Severe VSL would be late by four quarters based on the previous evaluation date.
Group
Peak Reliability
Jared Shakespeare
No
The Requirement should be revised to include "in its area" to allow for multiple Responsible entities in an Interconnection. R5.2: "DDR coverage" should be changed to "DDR coverage identification." It is not reasonable that the Responsible Entity ensure DDRs are placed into service, rather that they are identified and notification sent to owners. R5.3: Currently in the Western Interconnection, there is no established mechanism to determine BES Element owners. Also, the phrase "require DDR data when requested" is confusing. Is the Responsible Entity only required to notify owners that DDR is required and data may be requested in the future? Peak recommends rewording the Requirement to better reflect the intent. R5.4: "and implement the reevaluated list of BES Elements as per the Implementation Plan" should be deleted because it's not the responsibility of the Responsible Entity to implement, only to identify and notify. Deleting that phrase will make it consistent with R5.3.
No

"that meet the following" should be "to meet the following". Using "that" implies that the data that doesn't meet those requirements isn't applicable. We assume the SDT meant to convert all data to meet the time-synchronization requirements.
Yes
R12: "to the Regional Entity" should be "to the Regional Entity and to the Responsible Entity". This will ensure the Responsible Entity is aware of data outages.
Group
PPL NERC Registered Affiliates
Stephen J. Berger
Yes
Yes
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. We agree that DDR data should be obtained for the transmission lines from generation plants as listed in requirement 5, but not that GOs are the parties that should collect this information (R7). There has been much discussion between the North American Generator Forum (NAGF) and the Disturbance Monitoring Standard Development Team (DMSDT) regarding assignment of responsibility for monitoring disturbances, and we believe GOs should be excluded for the following reasons: - TOs interpret and use DME data; GOs do not. - TOs generally have wide-ranging arrays of DME, continuous recording/storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. - DDR data collected on the TO's side of the generation plant battery limits would be the same as that measured on the GO's side. - Disturbances are more likely to originate in the transmission system than in generation plants (as was the case for the Northeast blackout of 2003), and responsibility should rest with the party causing the need for monitoring. We understand that duplication of equipment is not mandated – a GO could contract with it's TO to supply DDR data. It may not be possible to negotiate such agreements, however, due to the impracticality of transferring compliance responsibilities and the GO risk exposure if TOs commit to sharing data but not to achieving PRC-002-2 compliance. The NAGF attempted to find common ground with the DMSDT by recommending that the standard should at least state that TOs are responsible for providing DDR data if they already have such equipment at plants, but this request was evidently rejected, and R7 as presently written is therefore likely to lead to widespread wasteful duplication of equipment and effort. The least-total-cost approach should be followed in obtaining the expected reliability benefits, and we believe that centralizing DME with TOs makes more sense than splitting the responsibilities between involved entities (TOs) and those who merely hand-over recordings (GOs) for further analysis. The entire subject of DME should be a TO matter and applicable to the TO's DME equipment that is already installed.
Group
Associated Electric Cooperative, Inc.
Phil Hart
Yes
1. AECI agrees with the SDT's list of elements. 2. Would the SDT provide some further clarification on exactly what "DDR coverage" would be considered? Further, some unofficial guidance was given to the effect that, neighboring entities DDR systems could be used for evidence if all required DDR data is collected by that unit. 5.3 goes on to state that notification to these entities is required, however provision of that data by the entity is not. Does the SDT believe the current language has sufficient measures to facilitate this "sharing" of DDR equipment?
Yes
No

Group
Duke Energy
Michael Lowman
Yes
Yes
No
Individual
Bill Temple
Northeast Utilities
No
The minimum requirements in R5.1 should be eliminated because they are overly inclusive. The Requirement should just be limited to R5.2 requirements. NU's Responsible Entity is on record as having adequate DDR monitoring for the region as such this requirement would add 20 DDR's to the region 10 in NU's footprint. The approximate cost to the region would be about $3 million with no benefit to system reliability.
No
NU does not support the revision to R10. NU has researched and found that there can be as much as 10 ms difference between the clock and time stamp. Recommend the SDT R10 should be returned to the previous draft
No
Individual
Bill Fowler
City of Tallahassee, TAL
Yes
Yes
TAL believe that disturbance monitoring though good for event analysis will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
Individual
Scott Langston
City of Tallahassee
Yes
Yes
TAL believes that disturbance monitoring though good for event analysis will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
Individual

Andrew Pusztai
American Transmission Company LLC
Yes
ATC recommends updating the verbiage of Requirement 5.1.4 to read, “One or more BES Elements that are part of an Operating or Planning Interconnection Reliability Operating Limit,” for clarification.
Yes
Yes
ATC recommends correcting the typographical error in Requirement 11.2. The text should read, “Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.”
Group
Florida Municipal Power Agency
Carol Chinn
No
It needs to be clear that 5.1.2 and 5.1.4 are dealing with SOLs and IROLs established for the Planning Horizon by the Planning Coordinator or Transmission Planner. Reliability Coordinator SOL methodologies are dealing with a shorter timeframe, in the Operating Horizon, within which it may not be possible to engineer, procure, and install the equipment necessary to meet the requirement, especially as the results of the application of the SOL methodologies may be changing as system conditions change. Also, the revised RSAW does not give any guidance to the auditor as to which set of SOLs and IROLs (Planning Horizon or Operating Horizon) to be looking at. There are some PCs that only have one BES bus, so 5.2 as written would require them to have a disproportionately higher percentage of DDR coverage than larger entities. FMPA suggests 5.2.1 be deleted in order to achieve a fairer tier to required DDR coverage. At the very least, 5.2.1 should be changed to “One BES Element; or” which we believe is what the drafting team intended. Taken together, 5.2.1 and 5.2.2 means at least two BES Elements need DDR coverage. Note that the clean version has 5.2.1 written as “One BES Element; and” while the redline version has it written as “One BES Element”
No
The requirement language still speaks to synchronizing the data even though the rationale states it should be the equipment and not the data that is mandated. There is also a grammar problem with the addition of the phrase “that meet the following:”. We believe it was intended that the equipment meet the 10.1 and 10.2 criteria and not the data or the BES Elements as it is worded. FMPA suggests the following language: “Each Transmission Owner and Generator Owner shall time synchronize all SER and FR equipment for the BES buses identified in Requirement R1 and all DDR equipment for the BES Elements identified in Requirement R5 to meet the following:”
FMPA believes the standard, as written, places an onerous burden upon small Transmission Owners and Planning Coordinators that may only have one or two BES buses. The language and methodology effectively guarantee that such small entities must install equipment and report data under the standard. In R1, FMPA believes the Responsible Entity should be the one applying the methodology in Attachment 1 instead of the Transmission Owner. It is more appropriate from a Functional Model perspective to have the Planning Coordinator, for example, obligate the Generator Owner to the requirements that follow. Also, the Responsible Entity has the wide area view that will allow for more dispersed equipment, and lessen the potential for duplicative coverage. The Responsible Entity may need to use data from the Transmission Owners in its area, but once it has the data the formula in Attachment 1 can be followed. There are logical problems, as well as, issues with the inherent tiering between smaller entities and larger entities with Attachment 1. In Step 2, 1500 MVA is too low for small entities with few busses because they are either in remote locations and pose little risk of causing wide-area events or are located near facilities of a large neighbor that drive up the short circuit MVA level of the buses they own. In the latter case, the neighboring facilities would be better candidates for SER and FR data and there would be no value in having additional data from the nearby facilities just because there is a different responsible entity. The main issue hinges upon the fact that the 1500 MVA threshold works well as an initial tool for evaluating large systems with many buses but does not work well as a singular and final compliance

threshold (which is what it becomes for small entities). FMPA suggests raising the 1500 MVA criteria in Step 2 to at least 3000 MVA (or higher) for entities with 11 buses or fewer in their system. Step 3, as worded, is confusing because it causes a list of 11 buses to be determined and then causes steps to be skipped if there are 11 or fewer buses, which will always be the case. FMPA suggests replacing in Step 2 the phrase "If there are no buses on the resulting list, proceed to Step 7." with "If the list has 11 or fewer buses, proceed to Step 7." and deleting the same phrase from Step 3. Zero is fewer than 11, so we believe this results in what the drafting team intended. In Step 7, the reference to Step 3 should be a reference to Step 2. The word "the" should be deleted in the phrase "at least the 10 percent". FMPA appreciates the SDT comment responses. Unfortunately, these responses do not mitigate the concerns raised in general about the need for the standard versus a guideline. Plus not all of our comments were addressed. Our prior concerns still remain in addition to some additional concerns. SDT Response 1:"The Standard Drafting Team realizes that improvements have been made to Disturbance Monitoring technology since the 2003 Northeast Blackout. That does not guarantee universal implementation, thus necessitating the need for the standard." --While the SDT may "realize" that improvements have been made over the last decade, the SDT has not provided a risk assessment to quantify the need for a standard versus a guideline recognizing the technology advances and PMU equipment installed through the DOE Smart Grid program over the last decade. A risk assessment would be a beneficial exercise to identify gaps first, as opposed to taking a broad brush approach. It would also provide for more focused impact and faster results. SDT Response 2: "PRC-002-2 addresses "what" data is recorded, not "how" the data is recorded. This approach eliminates the complications that might arise from the technological advances being made to record the data" --The fact that this standard is requiring data vs equipment does not mitigate the fact that equipment will need to be installed which raises a cost recovery concern that needs to be addressed. SDT Response 3: "The Disturbance Monitoring recordings can be used to improve reliability by providing information that can guide operators in better Real-time system management (Real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events." --Guiding operators goes beyond the scope of the standard for a number of reasons, but most importantly due to the fact the Time Horizon is "Long Term Planning" and not "Real-time Operations". This raises another concern, which is with regard to the purpose of the standard which now states: "To have adequate data available to facilitate ("event" has been removed) analysis of Bulk Electric System (BES) Disturbances (now upper case)". By removing "event" and capitalizing "Disturbance", which is very broadly defined in the NERC Glossary, this broadens the scope of the purpose of this standard. In R11, there is no defined need for which a Responsible Entity, Regional Entity or NERC can request all SER, FR and DDR data. FMPA believes criteria for making a data request is needed.
Individual
Karen Webb
City of Tallahassee
No
TAL believes that disturbance monitoring, though good for event analysis, will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
No
TAL believes that disturbance monitoring, though good for event analysis, will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
No
Group

Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes
Yes
Yes
1. It is believed that direct P & Q measurements are not required and the DDR can calculate these from measured voltages and currents- We recommend that the SDT clarify this in the Requirement or Rational box. 2. We would like the SDT to consider an alternative approach to this subject. It would be to have to have NERC or the RE’s develop a map of the BES with the locations of current DME, then determine the areas where additional DME is needed to analyze a system event? This would eliminate the shotgun approach of basing the install on MW values, and insure that the program is cost effective. Some of the Reliability Entities may already have enough recording equipment. For example RFC may have a map of their footprint from their 2010 data request.
Individual
John Brockhan
CenterPoint Energy Houston Electric
Yes
Yes
Yes
As stated in comments previously submitted regarding requirement R10 in conjunction with requirement R2, CenterPoint Energy continues to propose that UTC time synchronized DFR and DDR data is the final analysis tool and that, given the infrequent nature of wide area events, breaker state change SER data obtained from EMS systems provides adequate resolution for the initial phases of event analysis investigation. In CenterPoint Energy’s opinion the SDT has not provided sufficient justification to require such high resolution data in regards to breaker open/close SER data. While CenterPoint Energy recognizes this fine level of data may enhance analysis of a wide area event, the 2003 Blackout as well as other analysis’ of more recent wide area events indicates that this level of data is not critical to performing an accurate event analysis. CenterPoint Energy is concerned that this requirement may lead to applicable entities having to install additional SER equipment, communications infrastructure, or data gathering devices to be used only in the rare event that a wide area system disturbance occurs. Therefore, CNP recommends removing SER data from R10.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
Disturbance monitoring requirements should be established by the Regional Entity based on their overview of the BES, and monitoring equipment installed and maintained by the TO's to meet the requirements. GO's shoeuld not be included in the standard.
Individual
Andrew Gallo
Director, Reliability Compliance

Yes
City of Austin dba Austin Energy (AE) does not agree with this standard as a whole because it is too prescriptive and unnecessary in the ERCOT Region. Regional requirements for the ERCOT Region regarding disturbance monitoring equipment exist in the ERCOT Nodal Operating Guides, Section 6.1. (http://www.ercot.com/mktrules/guides/noperating/cur). Existing requirements provide sufficient data for disturbance monitoring and analysis. AE recognizes, as the SDT pointed out, the ERCOT requirement is not a NERC Reliability Standard. However, AE disagrees with the SDT's comment that the ERCOT requirements are not enforceable. Entities in the ERCOT Region must comply with the ERCOT requirements or face penalty by the Public Utility Commission of Texas (PUCT). Further, compliance with ERCOT requirements is monitored and enforced by Texas Reliability Entity, Inc. (Texas RE). AE suggests the SDT consider a regional variance for the ERCOT Region, because sufficient requirements already exist.
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Regarding requirement in 5.1.5: This requirement is very vague - "major voltage sensitive area" is not a defined term. I Recommend it be revised to reference UVLS programs that are required to maintain compliance with the TPL standards, or possibly place a MW limit of 300 or more MW of load shedding to qualify for consideration.
Group
Puget Sound Energy
Dianne Gordon
Yes
Yes
Yes
a) R3 could refer to R4 (see R4) in regards to details for each triggered FR. b) R8 discusses "continuous data and storage", whereas R11 states that data shall be retrievable for 10 days (presumably following an event), as data retention for longer is expensive and unrealistic. The statements in R8 and R11 may need clarification as to how much data needs to be held in memory before it is overwritten. Data from a catastrophic event may fill a recorder much more quickly than baseline data.
Individual
Glenn Hargrave
CPS Energy
Yes
Yes
While the revision is acceptable and allows the use of microprocessor relays, it would be much better to simply state an accuracy of the data as opposed to the device. With the way it is currently written, potentially a device itself could be synchronized very accurately to a clock while the data it records isn't required to have a specific measure of synchronization accuracy seems odd.
Still feel that the method for determining the busses is too complicated. While we agree that the methodology needs to have consistency, it needs to be made simpler. The spreadsheet is terrible. The examples are difficult to follow and a guide with screenshots needs to be provided to help follow along. For example, how does B3 become a hard-coded example of 64 in both examples when there

is nothing in the instructional steps indicating that this value needs to be changed? With hard to follow example, how can we be confident that we are following the procedure correctly to stay in compliance with our own data? The spreadsheet should be simplified to have users enter data without the zero busses, this may help to reduce the number of steps. A better way would be to write a program or something or make the planning coordinators produce the values generated by the spreadsheets. Also, bus fault MVA needs to be defined. Is this based on fault current and nominal voltages or pre-fault voltages? Are there any modeling requirements for generating the fault values? What needs to be recorded for each event - every terminal at a recorder location or just the faulted terminal? If we have microprocessor relays with GPS clock synchronization at every terminal in our system, would that be adequate enough - to capture each fault at the terminal where the fault was located?
Group
SPP Standards Review Group
Shannon V. Mickens
No
Part 5.2 - We do not fully understand exactly what Part 5.2 is requiring. The rational for Part 5.2 states that a 'Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous System Demand.' This we understand. The confusion comes from the phrase 'inclusive of those BES Elements identified in Part 5.1'. Does this mean the Elements selected must come from those Elements identified in Part 5.1? If that's the case, we suggest changing the phrase to 'from the BES Elements identified in Part 5.1'. Additionally, tying the requirement for DDR data to 3,000 MW of load seems arbitrary. Does the DMSDT have any data or other justification supporting this requirement? Wouldn't it be more meaningful to tie this requirement to system topology and connectivity? Rationale for R5 - Use lower case 'standard' in the 2nd line of the 4th paragraph. Insert 'of' between 'understanding' and 'why' in the last line of the 1st paragraph.
No
We suggest the wording in R10 be changed to read: '…identified in Requirement R5 to meet the following:'.
PRC-002-2 Thank you for the clarification in the Applicability Section regarding the use of 'Responsible Entity'. Rationale for R1 - In the 3rd line of the 4th paragraph, the phrase '…into the in force list,…' is used. Shouldn't this be '…into the currently enforced list,…' or '…into the current list,…'? Also, there is a font issue with the inserted sentence. Rationale for R4 - Hyphenate '30-cycle total minimum record length' and '30-contiguous cycles'. Rationale for R11 - Insert a hyphen and a space in '10-calendar day' at the beginning of the 2nd line of the 3rd paragraph. Attachment 1 R1, Step 7-Thank you for the additional clarification in Step 7. Guideline for Requirement R4-Hyphenate '30-cycle record length' in the 4th line of the 1st paragraph and '30-contiguous cycles' in the last line of the 1st paragraph. We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. We would ask that the drafting team take into consideration our suggestion to review the language mentioned in reference to the term 'list' in Attachment 1. Our concern at this point would be…. the term presents some confusion in how it's being used in the Steps of the documentation. For example in Step 3, we are not sure what 'list' you are referring to and will this term take on the same meaning as mentioned in the previous Steps (1 and 2)? We would request that you provide more clarity on which 'list' you are referring to and what data should be included in this process.
Group
DTE Electric Co.
Kathleen Black
No
The MVA level for generation is still a concern, but it is understood that this change will not be considered by the SDT. Will the Responsible Entity work to insure that the DDR equipment at shared GO/TO facilities is not duplicated? Also, it is suggested that the Responsible Entity include in their identification criteria an evaluation of monitored quantities versus installation expense. It seems unreasonable to require DDR data at a location where only two monitored quantities are needed.
No Comments

No Comments
Individual
John Merrell
Tacoma Power
No
Tacoma Power agrees that most of the revisions outlined above are improvements but we still believe that the standard as written requires utilities to spend more effort documenting data recording than necessary to reliably operate the BES. For example, within the WECC footprint there are 49 generators in WECC that meet the 500 MW threshold in R5.1.1.1. The minimum required number of DDRs based on load per R.5.2.2 is 52 generators. Thus the first 1/6th of the proposed requirement provides 94% of the prudent DDRs. Although we have not analyzed exactly how many DDRs will be required for R5.1.2 through R5.1.5, it is clear that the 1 per 3000 MW specified R5.2.2 has little correlation to how many are currently specified by R5.1. Instead, R5.2.2 should provide regulatory certainty by specifying a maximum number of DDRs that would be required to be documented as compliant with this NERC standard. We disagree with the changes to R5.1.5. Although a UVLS program is an indicator of a major voltage sensitive area, UVLS should not be the definition of “major voltage sensitive area.” There are remote portions of the system that may have UVLS, but they would not be classified as “major” since they have significantly less than 300 MW of load.
No
The revision now specifies the properties of the equipment, rather than specifying the accuracy of the SER and FR data. Under the revision, a utility could use the SCADA master at their control center as the SER recorder as long as the SCADA master met the synchronization requirement, irrespective of the communication delays between substations and the control center.
Yes
Although we agree focusing on “what” data rather than “how” data is a good idea, Measures M2 and M3 parts (1) and (3) are not consistent with that philosophy. Documented design specifications or station drawings are not evidence that the owner actually has SER/FR data; these documents are simply evidence of “how” the data might be captured rather than “what” data is actually being captured. In order to address the inconsistency between the requirement and the measure, the term “recording capability” should be inserted after the word “data” in Requirements R2 and R3. As currently written, this standard has a zero defect approach. A single missing piece of data is not a threat to the BES when analyzing historical events. In addition to the PRC-002-2 required recordings, most utilities have been installing microprocessor based relays with data recording capabilities. Requirement R5, Part 5.2.2, does not use the word ‘additional,’ but the Rationale for R5 does. If a Responsible Entity has 3,000 MW of historical simultaneous peak System Demand, are they required to have (at minimum) 1 or 2 locations with DDR? Requirement R5, Part 5.4, requires the Responsible Entity to implement the reevaluated list of BES Elements. However, the discussion in the Rationale for R5 says that the Transmission Owner and Generator Owner are responsible for implementation. It is understood that the Rationale for R5 is what is intended. Requirement R5, Part 5.4, ought to be amended to be consistent. In Measurement M9, it appears that the text “(R9, Part 9.1)” may be missing. In Requirement R11, Part 11.2, change “...unless and extension...” to “...unless an extension...” Requirement R11, Part 11.1, will likely drive (1) automatic event retrieval from relays used for FR/SER, (2) restriction of event triggers in relays (to the detriment of the entity’s other business objectives as they try to assure compliance for all scenarios), and/or (3) installation of dedicated FR equipment (or new relays) with large buffers. Buffers in many types of relays used for FR/SER could easily be overwritten within 10 calendar days, depending upon what event triggers are set up and power system conditions. It seems like the implementation plan for Requirements R2-R4 and/or R6-R11 in response re-evaluated lists from Requirement R1 or R5 should be included in the body of the standard. Implementation Plans are normally valid only for the initial phase-in of a standard (or new version of a standard). The response to a re-evaluated list is an ongoing activity.
Group
National Grid
Michael Jones

No
R5 / R5.1.2 may result in the implementation of more DDR equipment than is necessary for wide-area disturbance event analysis. Preliminary Planning Coordinator analysis indicates this concern.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
Yes
ERCOT agrees with the changes made to the BES Elements requiring data listed in R5, but have a concern over the other changes to R5 (and R1). Please see the comments provided in response to Q3.
Yes
Yes
ERCOT generally agrees with all the proposed changes and proposes some additional clarifications as provided below: • The addition of the phrase "and implement the reevaluated list of BES buses as per the Implementation Plan" to Part 1.3 and the phrase "and implement the reevaluated list of BES Elements as per the Implementation Plan" to Part 5.4 is unnecessary and makes the requirement out of date over time. The implementation timeframe should be stipulated in the Implementation Plan, not in the requirements. • R5.1.4 should be revised to state: One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL). • An additional sub-requirement should be added as R5.1.6, stating: 5.1.6 Any one BES Element that has previously demonstrated localized dynamic oscillations. • An additional sub-requirement should be added as R 5.1.7, stating: 5.1.7 Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. • Additionally, ERCOT respectfully submits that the RC/PC does not implement the plan, the TOs/GOs do (see paragraph 5 of Rationale for R5.) Accordingly, ERCOT recommends that R5.4 be revised to strike the last phrase as shown below: 5.4 Reevaluate all the identified buses BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part 5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan. • Requirement R8 should include a trigger for dynamic oscillations with less than 5% damping (whether local or inter-area). Requirement R8.2 should be reworded to identify triggers that are appropriate for the reasoning for the DDR identified in R5. For example, it is more appropriate for the trigger to be based on voltage for voltage sensitive areas. Gen locations would most likely trigger off (at least) frequency. ERCOT also recommends that the SDT consider the appropriate trigger for angular stability locations. For ERCOT, the off nominal frequency trigger should be set at 59.4 and 60.6 for ERCOT. This would give some additional bandwidth before entering 1st stage UFLS and catch the high frequency setpoint where generators should not trip off within 9 min. Additionally, the undervoltage trigger should be set consistently with that of the UVLS in the area. To set the trigger below the UVLS scheme would not utilize the equipment appropriately and the recording should be utilized to capture any UVLS event that would actually activate.
Group
ISO/RTO Council Standards Review Committee (SRC)
Greg Campoli
Yes
We agree with the changes made to the BES Elements requiring data listed in R5, but have a comment on other changes to R5 (and R1). Please see our comments under Q3.
Yes
No
We generally agree with all the proposed changes. However, the addition of the phrase "and implement the reevaluated list of BES buses as per the Implementation Plan" to Part 1.3 and the phrase "and implement the reevaluated list of BES Elements as per the Implementation Plan" to Part 5.4 is unnecessary and which makes the requirement out of date over time. The implementation

timeframe should be stipulated in the Implementation Plan, not in the requirements. We suggest the SDT to make this change, which can be regarded as not having material impact to the intent of the concerned requirements and hence may not require another round of successive balloting if this draft receives 2/3 majority support at the ballot
Group
Bonneville Power Administration
Andrea Jessup
No
R5.1.1 BPA believes gross individual nameplate rating greater than or equal to 500 MVA seems an appropriate measure for DDR as does aggregate gross plant/facility rating of 1000MVA. However, the 300MVA individual nameplate rating appears arbitrary and unnecessary. Facilities with greater than 1000MVA aggregate nameplate rating should have DDR capabilities associated with the point of interconnection regardless of individual unit size. R5.1.4 BPA believes the number of items selected under this requirement must be limited within the standard given that the Responsible Entity is requiring the Transmission Operator to invest money in the installation of DDR equipment and infrastructure based on the selection of “One or more BES Elements.” The Transmission Operator must be given the authority to select alternate elements for DDR monitoring as well the flexibility to defer or refuse to install monitoring on some elements for reasonable cause. BPA believes this would provide a more prudent balance between the need for monitoring and the cost of installation and maintenance.
No
BPA feels the designation of a minimum clock accuracy adds to the compliance burden that must be met by the Owner while providing no incremental benefit to the reliability of the system. Almost all dedicated FR and SER equipment exceeds this threshold making the requirement irrelevant. Relay based event monitoring equipment may not meet this requirement and would therefore need to be replaced while providing no incremental increase in the quality of the data provided. This requirement would be better communicated in a NERC guidance document.
Yes
BPA believes the authority and responsibility for installing Adequate FR, SER, and DDR equipment must be left to the individual TOs and GOs. These are the parties who will fund these, who know the system best and who will ultimately be responsible for the analysis of system events. It is appropriate that the Responsible Entity request desired locations for this equipment but the final siting decisions must be left to the Owner. Transmission and Generation Owners have long known the value of accurate and comprehensive disturbance monitoring for the purpose of system event analysis. BPA believes it is presumptive to assume that this new methodology for FR and SER placement will provide adequate data for system event analysis. Out of necessity most Transmission and Generation owners have already developed proven strategies for disturbance monitoring on their systems. BPA believes this standard should require Entities to develop their own methodology for monitoring. BPA believes Requirements 11.3, 11.4 and 11.5 go too far in stipulating the file format and naming convention for event data submissions. This is in direct conflict with the DMSDTs’ statement: “The standard deals with "what" data is recorded, not "how" it is recorded.” File formatting is an administrative detail and does not warrant regulatory scrutiny. BPA does not believe this Standard should require the Transmission Owner (TO) to notify other owners of BES equipment of their compliance responsibility with respect to this standard. As written, the notification requirement in R1.2 places an undue compliance risk on TOs and should be removed. BPA also believes the rationale of R3/M3 is a little flawed (if more than one GSU source is connected to the bus then excluding 4 won’t allow direct derivation of total fault current on the bus. This would be indirectly derived by comparison of the fault study results.
Individual
Larry Heckert
Alliant Energy
Yes
Yes

Consider revising Requirement R8 so that it refers to continuous recording and storage necessary to meet Requirement R11. Otherwise, it leaves the interpretation open that the user needs continuous unlimited storage of data.

Additional Comments:

JEA
Thomas McElhinney

We believe that the threshold of 1500MVA is too low

GASOC
Scott McGough

We support ACES Power Marketing comments with our negative ballot

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2007-11 Disturbance Monitoring

The Project 2007-11 Disturbance Monitoring Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from September 5, 2014 through October 21, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 51 sets of comments, including comments from approximately 137 different people from approximately 109 companies representing all 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

Stakeholder comments reflected that there were still questions regarding the standard addressing "what" data is captured, not "how" it is captured. The responses emphasized that quantities for fault recorder and dynamic disturbance recorder data can be determined (i.e. mathematically calculated from other data).

Stakeholders provided comments suggesting development of a guideline rather than a standard. A guideline will not ensure that there is adequate data available for event analysis continent-wide. Moreover, guidelines are unenforceable. The existing standards do not mandate the collection of the needed data for event analysis. The data mandated by PRC-002-2 can also be used in the refinement of models. The North American SynchroPhasor Initiative (NSAPI) has shown that the use of DDR data can dramatically improve modeling to reflect real system responses to Disturbances. DDR data may also be used for Real-time system operating management, especially in making restoration decisions.

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

Based on stakeholder comments, the Drafting Team made the following clarifying revisions to the standard:

- Added “4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator” to the Applicability section.
- Revised “interval” to “intervals” in Measure M1.
- Revised “the in force list” to “the currently enforced list” in Rationale for Requirement R1.
- Added wording to the Rationale for Requirement R3 similar to language found in the Rationale for R7.
- Revised Requirement R5, Part 5.2 from “Ensure” to “Identify” to be consistent with Requirement R5, Part 5.1.
- Added (R9, Part 9.1; R9, Part 9.2) to Measure M9.
- Removed the “Note” regarding the extensive revisions from previous posting at the beginning of Rationales for Requirements R10 and R11.
- Revised “devices” to “devices internal clock” in the Rationale for Requirement R10.
- Corrected spacing, hyphenation and capitalization errors.

Comment Form Questions:

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Janet Smith	Arizona Public Service Company	x				x	x				
N/A													
2.	Group	Guy Zito	Northeast Power Coordinating Council										x

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc,	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

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

8.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5

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

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Joe DePoorter	MRO NERC Standards Review Forum	x	x	x	x	x	x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4

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

8.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
9.	Marie Knox	MISO	MRO	2
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
11.	Randi Nyholm	Minnesota Power	MRO	1, 5
12.	Scott Nickels	Rochester Public Utilities	MRO	4
13.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
5.	Group	Brian Van Gheem	ACES Standards Collaborators						x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Luis Zaragoza	Sunflower Electric Power Corporation	SPP	1
2.	Alisha Anker	Prairie Power, Inc.	SERC	3
3.	Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	3, 5
4.	Scott Brame	North Carolina Electric Membership Corporation	RFC	3, 4, 5
5.	Paul Jackson	Buckeye Power, Inc.	RFC	3, 4, 5
6.	Matthew Caves	Western Farmers Electric Cooperative	SPP	1, 5
7.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
8.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
9.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

				1	2	3	4	5	6	7	8	9	10
6.	Group	Mike Garton	Dominion	x		x		x	x				

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

				1	2	3	4	5	6	7	8	9	10
7.	Group	Jared Shakespeare	Peak Reliability	x									

N/A

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1

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

2.	Brent Ingebrigtson	LG&E and KU Energy, LLC	SERC	3
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Montana, LLC	WECC	5
5.		PPL Susquehanna, LLC	RFC	5
6.	Elizabeth Davis	PPL Energy Plus, LLC	MRO	6
7.			NPCC	6
8.			SERC	6
9.			SPP	6
10.			RFC	6
11.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Phil Hart	Associated Electric Cooperative, Inc.	x		x		x	x				

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

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

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Carol Chinn	Florida Municipal Power Agency	x		x	x	x	x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3

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

5.	Randy Hahn	Ocala Utility Services	FRCC	3
6.	Don Cuevas	Beaches Energy Services	FRCC	1
7.	Stanley Rzad	Keys Energy Services	FRCC	4
8.	Mark Schultz	City of Green Cove Springs	FRCC	3
9.	Matt Culverhouse	City of Bartow	FRCC	3
10.	Tom Reedy	Florida Municipal Power Pool	FRCC	6
11.	Steven Lancaster	Beaches Energy Services	FRCC	3
12.	Richard Bachmeier	Gainesville Regional Utilities	FRCC	1
13.	Mike Blough	Kissimmee Utility Services	FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	x		x		x	x				
N/A													
13.	Group	Sandra Shaffer	PacifiCorp						x				
N/A													
14.	Group	Dianne Gordon	Puget Sound Energy	x		x		x					
N/A													
15.	Group	Shannon V. Mickens	SPP Standards Review Group		x								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jamison Cawley	Nebraska Power Review Board	MRO	1, 3, 5
2.	Louis Guidry	Cleco Power LLC	SPP	1, 3, 5, 6
3.	James Nail	City of Independence, Missouri	SPP	3, 5
4.	J.Scott Williams	City Utilities of Springfield	SPP	1, 4
5.	Robert Rhodes	Southwest Power Pool		2
6.	Shannon Mickens	Southwest Power Pool		2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Kathleen Black	DTE Electric Co.			x	x	x					

Additional Member	Additional Organization	Region	Segment Selection

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Michael Jones	National Grid	x		x							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brian Shanahan	National Grid	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee (SRC)		x								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Christina Bigelow	ERCOT	ERCOT	2
2.	Cheryl Moseley	ERCOT	ERCOT	2
3.	Charles Yeung	SPP	SPP	2
4.	Cathy Wesley	PJM	RFC	2
5.	Al DiCaprio	PJM	RFC	2
6.	Terry Bilke	MISO	MRO	2
7.	Ben Li	IESO	NPCC	2

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Heffernan	SPC Technical Svcs	WECC	1
2.	Jim Burns	Technical Operations	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Individual	Joe O'Brien on behalf of Chirag Patel	NIPSCO	x		x		x	x				
21.	Individual	Kayleigh Wilkerson	Lincoln Electric System	x		x		x	x				
22.	Individual	Amy Casuscelli	Xcel Energy	x		x		x	x				
23.	Individual	David Jendras	Ameren	x		x		x	x				
24.	Individual	David Thorne	Pepco Holdings Inc	x		x							
25.	Individual	Jo-Anne Ross	Manitoba Hydro	x		x		x	x				
26.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					x					
27.	Individual	Mark Wilson	Independent Electricity System Operator		x								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
28.	Individual	Thomas Foltz	American Electric Power	x		x		x	x				
29.	Individual	John Pearson/Matt Goldberg	ISO New England		x								
30.	Individual	Manon Paquet	Hydro-Quebec Production					x					
31.	Individual	Chris Scanlon	Exelon Companies	x		x		x	x				
32.	Individual	John Allen	City Utilities of Springfield, Missouri				x						
33.	Individual	Alshare Hughes	Luminant Generation Company, LLC					x	x	x			
34.	Individual	Anthony Jablonski	RelliabilityFirst										x
35.	Individual	Jamison Cawley	Nebraska Public Power District	x		x		x					
36.	Individual	Gul Khan	Oncor Electric Delivery LLC	x									
37.	Individual	Gul Khan	Oncor Electric Delivery LLC	x									
38.	Individual	Jonathan Meyer	Idaho Power	x									
39.	Individual	Karin Schweitzer	Texas Reliability Entity										x
40.	Individual	Bill Temple	Northeast Utilities	x									
41.	Individual	Bill Fowler	City of Tallahassee, TAL			x							
42.	Individual	Scott Langston	City of Tallahassee	x									
43.	Individual	Andrew Pusztai	American Transmission Company LLC	x									
44.	Individual	Karen Webb	City of Tallahassee					x					
45.	Individual	John Brockhan	CenterPoint Energy Houston Electric	x									
46.	Individual	Daniel Duff	Liberty Electric Power LLC					x					
47.	Individual	Andrew Gallo	Director, Reliability Compliance	x		x	x	x	x				
48.	Individual	Glenn Hargrave	CPS Energy	x		x		x					
49.	Individual	John Merrell	Tacoma Power	x		x	x	x	x				
50.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		x								
51.	Individual	Larry Heckert	Alliant Energy				x						

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

Summary Consideration:

Organization	Agree	Supporting Comments of “Entity Name”
N/A	N/A	N/A

1. **The DMSDT revised the requirements for Dynamic Disturbance Recorder (DDR) data based on stakeholder comments (see background section above). Do you agree with the BES Elements requiring DDR data listed in Requirement R5? If not, please provide technical justification**

Summary Consideration: Stakeholders comments reflected that there were still questions regarding the standard addressing "what" data is captured, not "how" it is captured. The responses emphasized that quantities for FR and DDR can be determined (i.e. mathematically calculated from other data). A standard is needed because a guideline would be unenforceable. Grammatical revisions and corrections to the standard were addressed.

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	We appreciate the DMSDT's decision to incorporate more explanation in the rationales of this standard based on its extensive outreach to event analysis subject matter experts. We feel that the DMSDT has taken steps to answer some of the concerns regarding the requirements that seek to find "why" an event occurred. However, we continue to disagree that the standard addresses the "what" of data collection and not the "how" the data is collected. How is an entity going to provide data if it does not have the equipment present to collect it? The fundamental principles of this standard seem flawed when the purpose of this standard is to have "adequate data available to facilitate analysis of BES Disturbances." We feel NERC can communicate the intent of collecting data for the purposes of explaining why an event occurred through a Reliability Guideline instead of an enforceable standard. NERC already has enforceable standards on reporting events, monitoring system conditions, and identifying entity-to-entity data specifications. The data collected and available through these existing standards are through "proactive" devices and applications, which entities then generally archive for historical and training purposes. We believe sufficient data is already available, as evident with the data available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California

Organization	Yes or No	Question 1 Comment
		Outages. As stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, “PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP).” The resulting report identified no additional standards because of this event. By continuing to pursue an enforceable standard to address outdated recommendations from the 2003 Blackout in the Northeast does not seem cost effective for both industry and NERC. A Reliability Guideline will not deter industry from installing additional or maintaining existing event recording devices. However, it gives industry an opportunity to balance the risk of not installing or maintaining such devices with pursing advancements in technologies with the more “proactive” and “preventable” devices and initiatives.
Response: Thank you for your comments. **For FR and DDR, the requirements specify that the electrical quantities can be determined (i.e. mathematically calculated from other data). Equipment is needed to capture only enough data to make the determination. A guideline will not ensure that there is adequate data available for event analysis continent-wide; guidelines are unenforceable. The existing standards do not mandate the collection of the needed data for event analysis. The data mandated by PRC-002-2 can also be used for Real-time system operating management.**		
Dominion	No	See comments in Question #3.
Response: Thank you for your comments.		
Peak Reliability	No	The Requirement should be revised to include "in its area" to allow for multiple Responsible entities in an Interconnection. R5.2: "DDR coverage" should be changed to "DDR coverage identification." It is not reasonable that the Responsible Entity ensure DDRs are placed into service rather that they are identified and notification sent to owners.

Organization	Yes or No	Question 1 Comment
		R5.3: Currently in the Western Interconnection, there is no established mechanism to determine BES Element owners. Also, the phrase "require DDR data when requested" is confusing. Is the Responsible Entity only required to notify owners that DDR is required and data may be requested in the future? Peak recommends rewording the Requirement to better reflect the intent. R5.4: "and implement the reevaluated list of BES Elements as per the Implementation Plan" should be deleted because it's not the responsibility of the Responsible Entity to implement, only to identify and notify. Deleting that phrase will make it consistent with R5.3.
Response: Thank you for your comments. **Requirement R5 was not revised to include the suggested language. Reliability Coordinator Area is a defined term while Planning Coordinator area is not. The Drafting Team believed that inclusion of this could cause confusion.** **The intent of Requirement R5, Part 5.2 is to ensure that there is DDR data captured for the particular Element, which identifies what is needed. Requirement R5, Part 5.2 is to ensure that there is data capture, "how" it is done is not the intent of the Part.** **Requirement R5, Part 5.3--The identification of the owner/owners of a BES Element should be readily available. Requirement R5, Part 5.3 dictates that the owners of the identified BES Elements that require data for that BES Element have it available anytime, because it can be requested at any time.** **Requirement R5, Part 5.4 was revised to remove ", and" and replace it with "to".**		
Florida Municipal Power Agency	No	It needs to be clear that 5.1.2 and 5.1.4 are dealing with SOLs and IROLs established for the Planning Horizon by the Planning Coordinator or Transmission Planner. Reliability Coordinator SOL methodologies are dealing with a shorter timeframe, in the Operating Horizon, within which it may not be possible to engineer, procure, and install the equipment necessary to meet the requirement, especially as the results of the

Organization	Yes or No	Question 1 Comment
		application of the SOL methodologies may be changing as system conditions change. Also, the revised RSAW does not give any guidance to the auditor as to which set of SOLs and IROLs (Planning Horizon or Operating Horizon) to be looking at. There are some PCs that only have one BES bus, so 5.2 as written would require them to have a disproportionately higher percentage of DDR coverage than larger entities. FMPA suggests 5.2.1 be deleted in order to achieve a fairer tier to required DDR coverage. At the very least, 5.2.1 should be changed to “One BES Element; or” which we believe is what the Drafting Team intended. Taken together, 5.2.1 and 5.2.2 means at least two BES Elements need DDR coverage. Note that the clean version has 5.2.1 written as “One BES Element; and” while the redline version has it written as “One BES Element”

Response: Thank you for your comments.

PRC-002-2 deals with capturing Real-time data, and as such the data captured as specified in Requirement R5, sub-Parts 5.1.2 and 5.1.4 needs to deal with in-use SOLs and IROLs. The time frames in the Implementation Plan are adequate and realistic for an entity to be able to establish data capture capability. Requirements R6 and R7 specify that DDR data is to be determined (i.e. mathematically calculated from other data).

The comment regarding the RSAW has been given to NERC compliance staff.

Requirement R5, Part 5.2 was included to ensure that “gaps” in DDR coverage were filled. The Rationale Box for Requirement R5 explains Part 5.2.

Organization	Yes or No	Question 1 Comment
SPP Standards Review Group	No	Part 5.2 - We do not fully understand exactly what Part 5.2 is requiring. The rational for Part 5.2 states that a ‘Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous System Demand.’ This we understand. The confusion comes from the phrase ‘inclusive of those BES Elements

Organization	Yes or No	Question 1 Comment
		identified in Part 5.1'. Does this mean the Elements selected must come from those Elements identified in Part 5.1? If that's the case, we suggest changing the phrase to 'from the BES Elements identified in Part 5.1'. Additionally, tying the requirement for DDR data to 3,000 MW of load seems arbitrary. Does the DMSDT have any data or other justification supporting this requirement? Wouldn't it be more meaningful to tie this requirement to system topology and connectivity? Rationale for R5 - Use lower case 'standard' in the 2nd line of the 4th paragraph. Insert 'of' between 'understanding' and 'why' in the last line of the 1st paragraph.
Response: Thank you for your comments. **The "inclusive" language of Part 5.2 was intended to avoid imposing additional data requirements. If an entity has two BES Elements identified in Part 5.1, then no further data is required. The 3,000 MW value selected for Requirement R5, sub-Part 5.2.2 was selected by the Drafting Team from experience and judgment. The Drafting Team has made the wording revisions suggested for the Rationale Box for Requirement R5.**		
DTE Electric Co.	No	The MVA level for generation is still a concern, but it is understood that this change will not be considered by the SDT. Will the Responsible Entity work to insure that the DDR equipment at shared GO/TO facilities is not duplicated? Also, it is suggested that the Responsible Entity include in their identification criteria an evaluation of monitored quantities versus installation expense. It seems unreasonable to require DDR data at a location where only two monitored quantities are needed.
Response: Thank you for your comment. **The standard addresses "what" data is captured, not "how" it is captured. The Responsible Entity, having wide-area oversight, should not prescribe duplicate data. Requirements R6 and R7 specify that DDR data can be determined (i.e. mathematically**		

Organization	Yes or No	Question 1 Comment
calculated from other data). If it is determined that there are only two monitored quantities, the reason for monitoring those two quantities is to ensure that there are no gaps in data coverage.		
National Grid	No	R5 / R5.1.2 may result in the implementation of more DDR equipment than is necessary for wide-area disturbance event analysis. Preliminary Planning Coordinator analysis indicates this concern.
Response: Thank you for your comment. **PRC-002-2 is not about "how" disturbance monitoring data is captured, but "what" data is captured. Requirements R6 and R7 also state that DDR can be determined (i.e. mathematically calculated from other data), which influences how much equipment needs to be installed to capture data for the identified Bulk Electric System Elements.**		
Bonneville Power Administration	No	R5.1.1 BPA believes gross individual nameplate rating greater than or equal to 500 MVA seems an appropriate measure for DDR as does aggregate gross plant/facility rating of 1000MVA. However, the 300MVA individual nameplate rating appears arbitrary and unnecessary. Facilities with greater than 1000MVA aggregate nameplate rating should have DDR capabilities associated with the point of interconnection regardless of individual unit size. R5.1.4 BPA believes the number of items selected under this requirement must be limited within the standard given that the Responsible Entity is requiring the Transmission Operator to invest money in the installation of DDR equipment and infrastructure based on the selection of "One or more BES Elements." The Transmission Operator must be given the authority to select alternate elements for DDR monitoring as well the flexibility to defer or refuse to install monitoring on some elements for reasonable cause. BPA believes this would provide a more prudent balance between the need for monitoring and the cost of installation and maintenance.
Response: Thank you for your comments.		

Organization	Yes or No	Question 1 Comment
Requirement R5, sub-Part 5.1.1--refer to the Guidelines and Technical Basis Section. For slowly evolving system disturbances, it is important to monitor individual generator response which would not be achieved from DDR at a multiple unit facility interconnection point. **Requirement R5, sub-Part 5.1.4--the Responsible Entity has the wide-area system overview to select the BES Elements that need DDR data captured. Requirement R5, sub-Part 5.1.4 "One or more BES Elements…" gives the Responsible Entity the leeway to have DDR for the appropriate BES Elements for meaningful data capture.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration L.P. (ICLP) agrees with the extensive and consistent negative response from a number of respondents to the previous posting regarding DDR. We (and they) believe that R5 will unnecessarily over-drive the deployment of phase measurement units (PMUs). PMUs are a fast improving technology and the DDR owners will quickly find that their equipment is obsolescent. We can agree that PMUs must be deployed in critical areas regardless, but do not see the same sense of urgency for locations of lesser BES importance. Specifically as a GO, ICLP agrees with the criteria developed in PRC-023 and CIP-002 to establish critical generation facilities. In our view, this would be those whose aggregate output exceeds 1500 MVA and attach to the BES at 200 kV or more. (Of course, there must be special consideration for facilities that are part of a SOL/IROL, but those locations are already captured in R5.) After the industry gains familiarity with PMU technology, further integration at lower capacities and voltages may be considered. By then, there will be far more exciting and useful options available - and will no doubt prove to be more useful to investigators trying to consolidate data related to a wide-area outage.
Response: Thank you for your comment. **Data acquisition for the BES Elements identified in Requirement R5 are necessary to ensure proper and expeditious event analysis. That data needed will not change in the future, and advances in data capture technology will only result in improvement.**		

Organization	Yes or No	Question 1 Comment
ISO New England	No	By definition, SOLs do not impact other areas and, for that reason, it would be more appropriate to leave the determination regarding monitoring of SOLs up to the Responsible Entity. Accordingly, Requirement 5.1.2 should be deleted. However, if Requirement 5.1.2 is not deleted, then the words “Any one” in Requirement 5.1.2 should be replaced with the words “One or more.” This will make it clear that the Responsible Entity is required to select one (or more) BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL) and will also make Requirement 5.1.2 consistent with Requirement 5.1.4, which already uses the words “One or more.” In Requirement 5.1.3, the word “circuit” should be replaced with the word “interconnection” or the word “facility” to ensure that back-to-back HVDC is monitored; these types of interconnections are being planned for New England and the word “circuit” may create confusion about monitoring them. Also, to make Requirement 5.1.3 clearer, the words “...for which the Responsible Entity is responsible” should be added at the end of the sentence. The words “Any one” should also be replaced with the words “One or more” in Requirement 5.1.5. Again, this will make it clear that the Responsible Entity is required to select one (or more) BES Element within a major voltage sensitive area as defined by an area with an in-service UVLS program, and will make the requirement consistent with Requirement 5.1.4.
Response: Thank you for your comments. **The Drafting Team has retained the original language of each Part. The intent of the Drafting Team is to only require one BES Element for Requirement R5, Parts 5.1.2 and Part 5.1.5.**		

Organization	Yes or No	Question 1 Comment
Requirement R5, sub-Part 5.1.3--The Drafting Team believes that the existing language is sufficient to capture both HVDC lines and back-to-back converters. Adding the words “for which the Responsible Entity is responsible” does not provide additional clarity.		
Exelon Companies	No	Regional DME criteria in RF was 1000 MVA, Exelon thinks the threshold in R5 should be raised to the 1000 MVA per the RF Criteria.
Response: Thank you for your comment. **Assuming that RF is referring to the 500MVA gross individual nameplate rating in Requirement R5, sub-Part 5.1.1.1, the Guidelines and Technical Basis Section for Requirement R5 explains the selection of that value.**		
City Utilities of Springfield, Missouri	No	City Utilities of Springfield, Missouri supports the comments submitted by the SPP Standards Review Group.
Response: Thank you for your comments. **Refer to the response to the SPP Standards Review Group.**		
RelliabilityFirst	No	ReliabilityFirst votes in the Affirmative and believes the standard helps ensure that adequate data is available to facilitate analysis of Bulk Electric System (BES) Disturbances. This standard also removes the “fill in the blank” aspects of the old PRC-002 and PRC-018 standards. ReliabilityFirst offers the following comments for consideration: 1. Requirement R5, Part 5.3 - Requirement R5, Part 5.3 requires notification within 90- calendar days of completion of Part 5.1, but then goes on to state “when requested”. ReliabilityFirst questions whether the intent is “within 90-calendar days” or “when requested”. ReliabilityFirst believes the SDT should choose one or the other. 2. Requirement R5, Part 5.4 - Requirement R5, Part 5.4 references an “Implementation Plan” and it is unclear to ReliabilityFirst how this will be enforced. The Implementation Plan only speaks to the initial identification

Organization	Yes or No	Question 1 Comment
		of buses and does not address the re-evaluation of the list. Furthermore, a NERC Reliability Standard should not have requirements that reference documents which are outside of the standard. ReliabilityFirst suggests this reference to Implementation Plan be removed from Part 5.4.
Response: Thank you for your comments. **The "when requested" aspect of Requirement R5, Part 5.3 is intended to relate to the data being in accordance with Requirement R11 and is not related to the notification.** **Requirement R5, Part 5.4--On Page 4 of the Implementation Plan under Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: compliance with the re-evaluated list is addressed. The reference to the Implementation Plan was added for clarity in response to comments received from previous postings.**		
Nebraska Public Power District	No	R5 5.2 states "5.2 Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: 5.2.1 One BES Element; and 5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand." Please explain how "Ensure a minimum DDR coverage" relates to the implementation plan where 100% compliance is required within 6 months of approvals. What is R5.2 acceptable evidence after 6 months? Is this just an identification requirement that the planning coordinator must provide in this 6 month time frame? This question arises because "Ensure" is used instead of "Identify". R5 question: For example, a utility has two DDRs on its system because it has two generating resources greater than 500 MVA at two separate locations. If this utility also has 3,030 MW peak demand will the two DDRs on its system satisfy R5.2? In addition to these comments, we also support the comments provided by SPP.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. **Requirement R5, Part 5.2--"ensure" has been replaced by "identify" as suggested. This aligns Requirement R5, Part 5.2 with 5.1 and the intent to identify those BES Elements for coverage.** **To satisfy Requirement R5, Part 5.2, data has to be captured for "One BES element, and "One BES Element per 3,000 MW…". DDR data for the two generating resources would satisfy Requirement R5, Part 5.2.** **Refer to the response to the SPP Standards Review Group.**		
	No	In the rationale for R5 it states "For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data." We do not think the Responsibility Entity should determine if the TO or GO will provide the data. Oncor recommends that if there is an interconnection between a TO and GO at the same BES location then the requirement should fall upon the GO. However if the TO has the data then the GO can contract with the TO for the data as mentioned in the rationale for R7 below:" Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data."
Oncor Electric Delivery LLC	No	In the rationale for R5 it states "For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data." We do not think the Responsibility Entity should determine if the TO or GO will provide the data. Oncor recommends that if there is an interconnection between a TO and GO at the same BES location then the requirement should fall upon the GO. However if the TO has the data then the GO can contract with the TO for the data as mentioned in the rationale for R7 below:" Generator Owners may install

Organization	Yes or No	Question 1 Comment
		this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.”
Response: Thank you for your comment. **The Responsible Entity determines what data is required, and is in the best position to determine what entity will provide it. The word “determine” is used in Requirement R7, and the Responsible Entity should take that into consideration.**		
Northeast Utilities	No	The minimum requirements in R5.1 should be eliminated because they are overly inclusive. The Requirement should just be limited to R5.2 requirements. NU’s Responsible Entity is on record as having adequate DDR monitoring for the region as such this requirement would add 20 DDR’s to the region 10 in NU’s footprint. The approximate cost to the region would be about $3 million with no benefit to system reliability.
Response: Thank you for your comment. **The BES Elements were specified in Requirement R5, Part 5.1 to ensure that adequate data would be provided for an event analysis. PRC-002-2 is not about “how” the data is captured, but “what” data is captured. Requirements R6 and R7 include the word “determine” which is intended to allow mathematical calculation or derivation of values from other data.**		
City of Tallahassee	No	TAL believes that disturbance monitoring, though good for event analysis, will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
Response: Thank you for your comment.		

Organization	Yes or No	Question 1 Comment
For FR and DDR, the requirements specify that the electrical quantities can be determined (i.e. mathematically calculated from other data). Equipment is needed to capture only enough data to make the determination. A guideline will not ensure that there is adequate data available for event analysis continent-wide; guidelines are unenforceable. The existing standards do not mandate the collection of the needed data for event analysis. The data mandated by PRC-002-2 can also be used in the refinement of models. The North American SynchroPhasor Initiative (NSAPI) has shown that the use of DDR date can dramatically improve modeling to reflect real system responses to disturbances. DDR data may also be used for Real-time system operating management, especially in making restoration decisions.		
Tacoma Power	No	Tacoma Power agrees that most of the revisions outlined above are improvements but we still believe that the standard as written requires utilities to spend more effort documenting data recording than necessary to reliably operate the BES. For example, within the WECC footprint there are 49 generators in WECC that meet the 500 MW threshold in R5.1.1.1. The minimum required number of DDRs based on load per R.5.2.2 is 52 generators. Thus the first 1/6th of the proposed requirement provides 94% of the prudent DDRs. Although we have not analyzed exactly how many DDRs will be required for R5.1.2 through R5.1.5, it is clear that the 1 per 3000 MW specified R5.2.2 has little correlation to how many are currently specified by R5.1. Instead, R5.2.2 should provide regulatory certainty by specifying a maximum number of DDRs that would be required to be documented as compliant with this NERC standard. We disagree with the changes to R5.1.5. Although a UVLS program is an indicator of a major voltage sensitive area, UVLS should not be the definition of “major voltage sensitive area.” There are remote portions of the system that may have UVLS, but they would not be classified as “major” since they have significantly less than 300 MW of load.
Response: Thank you for your comments. **Requirement R5, Part 5.2 is intended for the Responsible Entity to ensure that there are no gaps in DDR data for the BES. If an entity has had BES Elements identified in Requirement R5, Part 5.1 that meet these minimums, there are no additional DDR**		

Organization	Yes or No	Question 1 Comment
locations required. For example, if an entity has 6,500 MW of peak System Demand, that entity would be required, under Requirement R5, Part 5.2 to have DDR data for 3 BES Elements. If that entity has had 3 BES Elements identified in Requirement R5, Part 5.1, then they have met Requirement R5, Part 5.2. **Requirement R5, sub-Part 5.1.5: The Drafting Team notes that a remote portion of the system will not likely have any impact to BES reliability. The intent of having the DDR data is to analyze disturbances. From the Guidelines and Technical Basis Section of the standard for Requirement R5:** **"Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.)."**		
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
MRO NERC Standards Review Forum	Yes	
PPL NERC Registered Affiliates	Yes	
Associated Electric Cooperative, Inc.	Yes	1. AECI agrees with the SDT's list of elements. 2. Would the SDT provide some further clarification on exactly what "DDR coverage" would be considered? Further, some unofficial guidance was given to the effect that, neighboring entities DDR systems could be used for evidence if all required DDR data is collected by that unit. 5.3 goes on to state that notification to these entities is required, however provision of that data by the entity is not. Does the SDT believe the current

Organization	Yes or No	Question 1 Comment
		language has sufficient measures to facilitate this "sharing" of DDR equipment?
Response: Thank you for your comments. **DDR coverage is referring to DDR data capture for the BES Elements identified in Requirement R5, Part 5.1. PRC-002-2 is not about "how" data is captured, but "what" data is captured. The standard is concerned with ensuring that adequate data is captured for event analysis. The Requirements for data (R6 and R7) allow the data to be determined (i.e. mathematically calculated). If a neighboring entity has sufficient data to determine the quantities required, an entity may implement a data sharing arrangement. Those details are left to the entity. Requirement R5, Part 5.3 does state that DDR data just be provided when requested. The actual request and provision of data is addressed in Requirement R11.**		
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
PacifiCorp	Yes	
Puget Sound Energy	Yes	
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the changes made to the BES Elements requiring data listed in R5, but have a concern over the other changes to R5 (and R1). Please see the comments provided in response to Q3.
Response: Thank you for your comments.		

Organization	Yes or No	Question 1 Comment
Please see responses to your comments under Question 3.		
Independent Electricity System Operator	Yes	We agree with the changes made to the BES Elements requiring data listed in R5, but have concerns over the other changes to R5 (and R1). Please see our comments under Q3.
Response: Thank you for your comments. **Please see responses to your comments under Question 3.**		
ISO/RTO Council Standards Review Committee (SRC)	Yes	We agree with the changes made to the BES Elements requiring data listed in R5, but have a comment on other changes to R5 (and R1). Please see our comments under Q3.
Response: Thank you for your comments. **Please see responses to your comments under Question 3.**		
Ameren	Yes	We believe that Requirement R5 as written would require the addition of about a dozen additional PMUs to our system. For us this number would be much more manageable than the number called for in earlier drafts of this standard. Because this draft targets monitoring generators of significant size, disturbance monitors can potentially generate disturbance data useful in refining dynamic model representations for this equipment over time.
Response: Thank you for your comment.		
Pepco Holdings Inc	Yes	
Manitoba Hydro	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 1 Comment
Hydro-Quebec Production	Yes	
Luminant Generation Company, LLC	Yes	
Idaho Power	Yes	
Texas Reliability Entity	Yes	
American Transmission Company LLC	Yes	ATC recommends updating the verbiage of Requirement 5.1.4 to read, "One or more BES Elements that are part of an Operating or Planning Interconnection Reliability Operating Limit," for clarification.
Response: Thank you for your comment. **An IROL is defined in the NERC Glossary as "A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System." The Drafting Team does not believe that additional clarification is needed.**		
CenterPoint Energy Houston Electric	Yes	
CPS Energy	Yes	
Alliant Energy	Yes	

2. **The DMSDT revised Requirements R10 regarding time synchronization of data and added explanation regarding time synchronization as follows to the rationale: "Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the standard devices used for monitoring are within ± 2 ms accuracy will suffice with respect to providing time synchronized data." Do you support these revisions? If not, please explain why and provide suggested changes**

Summary Consideration: Stakeholders provided comments suggesting development of a guideline rather than a standard. A standard is needed because a guideline would be unenforceable. The Rationale for Requirement R10 addressed stakeholders concerns expressed in the comments received. Grammatical revisions and corrections to the standard were addressed.

Organization	Yes or No	Question 2 Comment
ACES Standards Collaborators	No	We feel that NERC can communicate technical specifications for data collection explaining why an event occurred through a Reliability Guideline. As stated on the NERC web site, "reliability guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability." We feel NERC and industry jointly pursuing a Reliability Guideline on this topic collaboratively would be better use of time and resources.
Response: Thank you for your comment. **Because it is necessary to ensure time synchronization of data to facilitate analysis, it is necessary to be included in the standard because guidelines are unenforceable.**		
Dominion	No	See comments in Question #3.
Response: Thank you for your comments. **Please see responses to your comments under Question 3.**		

Organization	Yes or No	Question 2 Comment
Peak Reliability	No	"that meet the following" should be "to meet the following". Using "that" implies that the data that doesn't meet those requirements isn't applicable. We assume the SDT meant to convert all data to meet the time-synchronization requirements.
Response: Thank you for your comment. **Requirement R10 was revised as suggested.**		
Florida Municipal Power Agency	No	The requirement language still speaks to synchronizing the data even though the rationale states it should be the equipment and not the data that is mandated. There is also a grammar problem with the addition of the phrase “that meet the following:”. We believe it was intended that the equipment meet the 10.1 and 10.2 criteria and not the data or the BES Elements as it is worded. FMPA suggests the following language:” Each Transmission Owner and Generator Owner shall time synchronize all SER and FR equipment for the BES buses identified in Requirement R1 and all DDR equipment for the BES Elements identified in Requirement R5 to meet the following:”
Response: Thank you for your comment. **Requirement R10 was revised by changing “that” to “to. The remainder of the original language was retained as the Drafting Team feels that the language is clear in its intent.**		
SPP Standards Review Group	No	We suggest the wording in R10 be changed to read: ‘...identified in Requirement R5 to meet the following:’.
Response: Thank you for your comment. **Requirement R10 was revised as suggested.**		
Bonneville Power Administration	No	BPA feels the designation of a minimum clock accuracy adds to the compliance burden that must be met by the Owner while providing no incremental benefit to the reliability of the system. Almost all dedicated FR and SER equipment exceeds this threshold making the requirement irrelevant. Relay based event monitoring

Organization	Yes or No	Question 2 Comment
		equipment may not meet this requirement and would therefore need to be replaced while providing no incremental increase in the quality of the data provided. This requirement would be better communicated in a NERC guidance document.
Response: Thank you for your comment. **Because it is necessary to ensure time synchronization of data to facilitate analysis, it is necessary to be included in the standard because guidelines are unenforceable.**		
Lincoln Electric System	No	Within the Rationale for Requirement R10, it is unclear which device the Drafting Team intends to be synchronized to within +/- 2 milliseconds of UTC. Although the last paragraph of the Rationale for R10 states that the “accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment”, the following sentence states that “the equipment used to measure the electrical quantities must be synchronized to +/-2 ms accuracy”. This creates confusion in terms of whether the accuracy requirement applies to the clock used for synchronizing the monitoring equipment, to the monitoring equipment itself, or to both. Recommend additional clarification be included within the Rationale for R10 or else to R10.2 to prevent further confusion.
Response: Thank you for your comment. **The Drafting Team replaced the word “devices” in the last sentence of the Rationale to “devices internal clocks”.**		
City Utilities of Springfield, Missouri	No	City Utilities of Springfield, Missouri supports the comments submitted by the SPP Standards Review Group.
Response: Thank you for your comments. **Refer to the responses to the SPP Standards Review Group.**		
Nebraska Public Power District	No	We support the comments provided by SPP.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **Refer to the responses to the SPP Standards Review Group.**		
Northeast Utilities	No	NU does not support the revision to R10. NU has researched and found that there can be as much as 10 ms difference between the clock and time stamp. Recommend the SDT R10 should be returned to the previous draft
Response: Thank you for your comment. **Requirement R10 was previously revised to address synchronization of only the time clock in recognition of the time difference between the clock and time stamp. Refer to the Rationale for R10.** **Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring device clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.**		
City of Tallahassee	No	TAL believes that disturbance monitoring, though good for event analysis, will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
Response: Thank you for your comment. **A guideline will not ensure that there is adequate data available for event analysis continent-wide; guidelines are unenforceable. The existing standards do not mandate the collection of the needed data for event analysis. The data mandated by PRC-002-2 can also be used in the refinement of models. The North American SynchroPhasor Initiative (NSAPI) has shown that the use of DDR**		

Organization	Yes or No	Question 2 Comment
date can dramatically improve modeling to reflect real system responses to Disturbances. DDR data may also be used for Real-time system operating management, especially in making restoration decisions.		
Tacoma Power	No	The revision now specifies the properties of the equipment, rather than specifying the accuracy of the SER and FR data. Under the revision, a utility could use the SCADA master at their control center as the SER recorder as long as the SCADA master met the synchronization requirement, irrespective of the communication delays between substations and the control center.
Response: Thank you for your comment. **The standard is not about "how" the data is recorded, and a SCADA master at a control center could be used. Analysis of data would have to consider the time delays.**		
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
MRO NERC Standards Review Forum	Yes	
PPL NERC Registered Affiliates	Yes	
Associated Electric Cooperative, Inc.	Yes	
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.;	Yes	

Organization	Yes or No	Question 2 Comment
Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
PacifiCorp	Yes	
Puget Sound Energy	Yes	
ISO/RTO Council Standards Review Committee (SRC)	Yes	
Ameren	Yes	Based on our experience it would be difficult to keep communications network delays within the +/- 2 millisecond window. In our opinion, a reasonable approach would be to limit this requirement to the synchronizing clock equipment as shown in the modified draft standard, which would be feasible and sufficient.
Response: Thank you for your comment. **Requirement R10, Part 10.2 had been previously added to address "Synchronized device clock accuracy…".**		
Pepco Holdings Inc	Yes	
Manitoba Hydro	Yes	
Ingleside Cogeneration LP	Yes	

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	Yes	
American Electric Power	Yes	
ISO New England	Yes	
Hydro-Quebec Production	Yes	
Oncor Electric Delivery LLC	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power	Yes	
Texas Reliability Entity	Yes	
City of Tallahassee, TAL	Yes	
City of Tallahassee	Yes	
American Transmission Company LLC	Yes	
CenterPoint Energy Houston Electric	Yes	
CPS Energy	Yes	While the revision is acceptable and allows the use of microprocessor relays, it would be much better to simply state an accuracy of the data as opposed to the device. With the way it is currently written, potentially a device itself could be synchronized

Organization	Yes or No	Question 2 Comment
		very accurately to a clock while the data it records isn't required to have a specific measure of synchronization accuracy seems odd.
Response: Thank you for your comment. **The Rationale for Requirement R10 explains the synchronization of the clock.** **"Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data."**		
Electric Reliability Council of Texas, Inc.	Yes	
Alliant Energy	Yes	
DTE Electric Co.		No Comments

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

Summary Consideration: The inclusion of the reference to the Implementation Plan in the standard was raised by the stakeholders. The inclusion of the Implementation Plan was added for clarity in response to comments received from previous postings. There were alternatives submitted to the specification of ASCII .CSV in Part 11.3. .CSV was specified to ensure consistency of data submitted. Regarding the submission of the CAP to the Regional Entity (Requirement R12) it was decided to just have the CAPs go to the Regional Entity because the Regional Entity is in a better position to have an overview of the data recording capability for its area. Comments regarding Attachment 1 were addressed in the responses. Concerns over triggered DDR were raised and addressed in the responses. The need for specific DDR data from individual generators versus combined data from the Transmission System was explained because of the importance of generator behavior during System Disturbances. DDR data being used to analyze slowly

evolving System Disturbances was emphasized in the responses to comments. Grammatical revisions and corrections to the standard were addressed.

Organization	Yes or No	Question 3 Comment
Arizona Public Service Company	No	
Associated Electric Cooperative, Inc.	No	
Duke Energy	No	
ISO/RTO Council Standards Review Committee (SRC)	No	We generally agree with all the proposed changes. However, the addition of the phrase "and implement the reevaluated list of BES buses as per the Implementation Plan" to Part 1.3 and the phrase "and implement the reevaluated list of BES Elements as per the Implementation Plan" to Part 5.4 is unnecessary and which makes the requirement out of date over time. The implementation timeframe should be stipulated in the Implementation Plan, not in the requirements. We suggest the SDT to make this change, which can be regarded as not having material impact to the intent of the concerned requirements and hence may not require another round of successive balloting if this draft receives 2/3 majority support at the ballot
Response: Thank you for your comment. **On Page 4 of the Implementation Plan under Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: compliance with the re-evaluated list is addressed. The reference to the Implementation Plan in Requirement R1, Part 1.3 and Requirement R5, Part 5.4 was added for clarity in response to comments received from previous postings.**		
Pepco Holdings Inc	No	

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	No	
Hydro-Quebec Production	No	
Idaho Power	No	
Northeast Utilities	No	
City of Tallahassee	No	
Northeast Power Coordinating Council	Yes	Include the Quebec Interconnection in the Introduction Section 4 Applicability. Add to “4.1 The Responsible entity is:” 4.1.4 Quebec Interconnection - Planning Coordinator or Reliability Coordinator. As an alternative, define a Responsible Entity for non-specified Interconnection areas. M12 - Remove “of”. Requirement R1, Part 1.2 requires from each Transmission Owner (TO) to notify other owners of BES Elements connected to identified BES buses. It is recommended to revise Part 1.2 to read that each TO provides the list of identified BES buses to their PC / RC who will notify those owners whose BES Elements require SER data and/or FR data. The PC / RC has more authority to maintain a master list of BES buses that require SER and FR data that can provide maximum wide-area coverage. This may avoid TO’s being challenged regarding BES bus selection. Requirement R11, Part 11.3. requires SER data in Comma Separated Value (.CSV) format following Attachment 2 whereas the majority of Disturbance Monitoring Equipment (DME) does not save data in this format. If large data volumes are requested then TO / GO should have their say to the requestor about when they can provide the data in (.CSV) format. Some DME produces records from which SER data would need to be manually extracted, which is very time-consuming. However, the same SER data can be visually seen using COMTRADE viewing software. The standard

Organization	Yes or No	Question 3 Comment
		should not make a file format (such as .CSV) a mandatory requirement. Additionally, Part 11.3 asks to combine SER data from multiple DME devices and from multiple stations. This could be very time consuming and subject to errors.
Response: Thank you for your comments. **The Quebec Interconnection was added as suggested to the Applicability section.** **"of" was removed from M12.** **The TO is in the best position to evaluate what BES Elements in its area will require Disturbance monitoring, and is in the best position to make the notifications.** **Regarding Requirement R11, Part 11.3, refer to the Rationale Box for Requirement R11:** **"SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve a common data format for event records, enabling the use of software tools for analyzing the SER data."**		
Seattle City Light	Yes	Seattle City Light does not support this Standard as structured or as written. We believe siting of monitoring equipment should be coordinated at a higher (regional or sub-regional) level to promote the most cost-effective installations. We do not believe the proposed level of technical detail (which changes constantly as technologies improve and change) is appropriate to a federal Standard (which is very difficult and slow to update and change). Finally, if a Standard something like the proposed approach is necessary, we find the 1500 MVA fault duty values to be low by a factor of 3 or 4, if not perhaps by a factor of 10.
Response: Thank you for your comment. **PRC-002-2 does not address "how" data is captured, but "what" data is captured. The technical requirements identified are minimum requirements, and as technology improves those requirements will be recognizably exceeded. The 1,500 MVA three phase short circuit was chosen based on input from across the continent and the Drafting Team's judgment.**		

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Forum	Yes	
ACES Standards Collaborators	Yes	(1) When compared to other enforceable standards, the number of requirements identified in this standard is greater than the number of requirements currently enforceable for standards related to event reporting and entity-to-entity data specifications. We continue to believe that many of these requirements are unnecessary and fall under Paragraph 81 Criteria B. However, if the DMSDT feels that such information is "essential to expeditious and efficient data analysis," we believe these technical specifications could be included in a technical guideline or Compliance Section attached to this standard. Requirements R4 and R9 regarding data sampling and requirement R10 regarding time synchronization are just three of the numerous specifications listed in this standard. Requirement R11 identifies the data format and nomenclature expected for entities to follow. Even the current requirements associated with the Disturbance Control Standard, NERC Standard BAL-002-1, do not identify the data format as a requirement. Moreover, the individual parts of requirement R11 cite various IEEE standards and specifications, references the DMSDT could identify as footnotes. Many other SDTs, such as the one that developed NERC Standard PRC-023-2, relocated their technical information to other appropriate areas or documents. Likewise, requirement R8 identifies system conditions that are necessary to trigger the initiation of data recording if continuous data recording is unavailable. We believe the DMSDT should move these technical specifications to an appendix of the standard and not identify them as enforceable requirements. (2) We concur with the DMSDT that the term "BES buses" provides confusion. We believe requirements R1.1 and R1.3 should be rewritten to "BES Elements connected to a BES bus" to alleviate any further confusion.

Organization	Yes or No	Question 3 Comment
		(3) We believe the term “and/or” listed in Requirement R1.2 could provide confusion. We recommend change the requirement to read, “Notify, within 90-calendar days, other owners of BES buses identified within R1.1 that require SER data and FR data.” (4) We believe the DMSDT should remove references to the Implementation Plan, as embedded directly within the requirement text, and incorporated this information into an “Effective Date” entry listed under the Introduction (Section A) of this standard. Such references include R1.3 and R5.4. (5) We believe the DMSDT should remove the reference to “local time offset” in Requirement R10.1. Its reference to the time listed in SER and FR data and their synchronization to Coordinated Universal Time (UTC) is an unnecessary addition to the text of this requirement. (6) Requirement R11 identifies that entities are required to provide all SER and FR data, upon request, to the Regional Entity and NERC. NERC already defines this mechanism in Section 1600 of the NERC Rules of Procedures. We suggest the DMSDT remove all references to the Regional Entity and NERC from this requirement. (7) Requirement R12 states that an entity should first submit a Corrective Action Plan (CAP) to its Regional Entity and then implement the plan. We recommend the DMSDT follow a similar approach taken in NERC Standard PRC-004-3, where the entity is first required to develop a CAP and then required to implement and provide updates until the plan is completed. Both industry and NERC have already reviewed this language and the standard is currently on file with FERC. (8) The term “Responsible Entity” is already a defined term in Appendix 2 of the NERC Rules of Procedures. We recommend the DMSDT revise all references to Responsible Entity within this standard accordingly. (9) We continue to disagree with the DMSDT that this standard addresses the “what” of data collected and not “how” the data is collected. The costs of installing new equipment for the purposes of disturbance monitoring could be significant for some of our members. Moreover, industry has already benefitted from the DOE grants to

Organization	Yes or No	Question 3 Comment
		install PMUs and would continue to benefit from these types of financial incentives for continual situational awareness. The DMSDT continues to rebut our previously submitted comments with references to the 2003 Blackout in the Northeast. However, it was through these financial incentives, that sufficient data was available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California Outages. As stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, "PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP)." Moreover, the resulting report identified that no additional standards were necessary because of this event. We suggest NERC should develop a Reliability Guideline on this topic instead of a standard, as we do not see the cost benefit or justification to allocate resources for an issue that is not a high priority for reliability.(10) Thank you for the opportunity to comment.

Response: Thank you for your comments.

1) **The technical specifications are included because a guideline will not ensure that they are adhered to. The technical specifications were included to ensure that the data captured would be able to be expeditiously analyzed. Guidelines are unenforceable. The existing standards do not mandate the collection of the needed data for event analysis. The data mandated by PRC-002-2 can also be used for Real-time system operating management, especially in making restoration decisions.**
2) **Requirement R1 was revised to clarify BES Elements connected to BES buses (Part 1.2) in the last revision. BES buses are the foundation for determining what data needs to be captured.**
3) **Requirement R1, Part 1.2 has "and/or" because not all BES buses have BES Elements that require both SER and FR data. In some instances, the requirement will be only for SER or FR data.**
4) **The reference to the Implementation Plan was added for clarity in response to comments received from previous postings.**
5) **Local time offset was included to accommodate entities that synchronize device clocks to their local time.**
6) **Requirement R11--The Drafting Team felt it necessary to specify who requests the data. A Section 1600 data request is very different from a data request under this standard.**

Organization	Yes or No	Question 3 Comment
7) Requirement R12 was written to realistically address recording capability failure. Implementation of the CAP requires the entity to perform the actions necessary to restore the data recording capability. 8) Responsible Entity as defined in the Applicability (section 4.1) is solely for use in PRC-002-2. This "Responsible Entity" for Requirement R5 varies by Interconnection. 9) PRC-002-2 addresses "what", not "how". Requirements R3, R6 and R7 include "to determine" which directly influences what capability is needed for System Disturbance monitoring. The existing standards do not mandate the collection of the needed data for event analysis. The data mandated by PRC-002-2 can also be used in the refinement of models. The North American SynchroPhasor Initiative (NSAPI) has shown that the use of DDR date can dramatically improve modeling to reflect real System responses to Disturbances. DDR data may also be used for Real-time System operating management, especially in making restoration decisions.		
Dominion	Yes	Project 2007-11 Disturbance Monitoring was initiated to replace the existing fill-in-the-blank Reliability Standard PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements with a more comprehensive standard. Project 2007-11 began in March 2007 with the objective to develop a continent-wide Disturbance Monitoring (DM) Reliability Standard. One Regional Entity (NPCC) developed a DM Regional Reliability Standard (FERC approved) in absence of a continent-wide standard. Dominion does not support this Reliability Standard and recommends that the SDT consider the following: 1. Is a continent-wide DM Reliability Standard necessary? With the exception of NPCC, no other Regional Entity has a Regional Reliability Standard for DM. Perhaps existing regional guidance/practices employed since 2007 are sufficient. There has been many new installations of DM equipment since the Version 0 fill in the blank standard was remanded back to NERC. Perhaps a suitable alternative to a standard would be for NERC to issue guidance similar to guidance that was issued for cold weather preparedness in lieu of a standard. 2. Duplicity and/or differences between Regional Reliability Standard and continent-wide Reliability Standard. Specifically: Dominion remains concerned that PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance

Organization	Yes or No	Question 3 Comment
		Monitoring. As of October 20, 2014, NPCC applicable entities are three years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements. Once approved, NPCC applicable entities must comply with both PRC-002-2 and PRC-002-NPCC-01, requiring those entities to review and determine the more stringent requirements between the regional and continent-wide standards. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01). 3. Equipment installation may be necessary to obtain the data specified in the Reliability Standard. Considering the criteria, some merchant generators, but not all, will incur costs that are not recoverable to install the equipment. This results in an unfair competitive advantage for some market participants. 4. Please consider the following items for consistency:M1 needs to be updated to include Parts 1.1, 1.2, and 1.3, similar to how M4 and M5 included the Parts. R11.1 should be reworded to include the word “consecutive” to read “period of 10 consecutive calendar days” and change test from “the data was recorded” to “the data was requested.”

Response: Thank you for your comments.

1. Project 2007-11 – Disturbance Monitoring was initiated to address the existing PRC-002-1 “fill in the blank” standard. FERC did not approve or remand PRC-002-1 in its Order No. 693 (March 16, 2007) because the standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities. This project intends to address FERC concerns in Order 693, specifically the “fill in the blank” aspects of PRC-002-1, and PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting (to be retired upon approval of PRC-002-2). PRC-002-2 is intended to ensure that there are no gaps in Disturbance monitoring data coverage continent-wide for System disturbances. A

Organization	Yes or No	Question 3 Comment
guideline will not ensure that there is adequate data available for event analysis continent-wide; guidelines are unenforceable. The existing standards do not mandate the collection of the needed data for event analysis. The data mandated by PRC-002-2 can also be used in the refinement of models. The North American SynchroPhasor Initiative (NSAPI) has shown that the use of DDR date can dramatically improve modeling to reflect real system responses to Disturbances. DDR data may also be used for Real-time system operating management, especially in making restoration decisions. 2. After approval of PRC-002-2, PRC-002-NPCC-01 will have to be reviewed for duplication of requirements. It is possible that NPCC will determine that PRC-002-NPCC-01 can be retired. Because PRC-002-2 deals with "what", not "how", complying with PRC-002-NPCC-01 might meet many, if not all of the requirements of PRC-002-2. 3. PRC-002-2 is just concerned with the capture of data and reporting of electrical quantities. It should be noted that entities may determine the required electrical quantities specified by using data from other sources. This includes a GO obtaining data from a TO to be able to determine their required electrical quantities. 4. Measure M1: The original language was retained as the use of "Requirement R1" covers all of the Parts. Requirement R11, Part 11.1 was not revised to add the word "consecutive" because the Drafting Team believes this is clear within the requirement. Changing "the data was recorded" to "the data was requested" would change the intent of the requirement. As written, Requirement R11, Part 11.1 limits the amount of data storage required to 10 days. Basing the storage on the request would create a potentially unlimited storage requirement. The use of the word "recorded" is appropriate.		
Peak Reliability	Yes	R12: "to the Regional Entity" should be "to the Regional Entity and to the Responsible Entity". This will ensure the Responsible Entity is aware of data outages.
Response: Thank you for your comment. The Standard Drafting Team discussed the submission of Corrective Action Plans to the Responsible Entity. It was decided to have the CAPs just go to the Regional Entity because the Regional Entity is in a better position to have an overview of the data recording capability for its entire area.		

Organization	Yes or No	Question 3 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	1. It is believed that direct P & Q measurements are not required and the DDR can calculate these from measured voltages and currents- We recommend that the SDT clarify this in the Requirement or Rational box. 2. We would like the SDT to consider an alternative approach to this subject. It would be to have to have NERC or the RE's develop a map of the BES with the locations of current DME, then determine the areas where additional DME is needed to analyze a system event? This would eliminate the shotgun approach of basing the install on MW values, and insure that the program is cost effective. Some of the Reliability Entities may already have enough recording equipment. For example RFC may have a map of their footprint from their 2010 data request.
Response: Thank you for your comments. **1. Requirements R6 and R7 stipulate "data to determine" the quantities of concern. The Rationale for Requirement R6 also states this.** **2. After review of the BES buses identified by the Attachment 1 process, it was judged that this gives adequate coverage of the BES for Disturbance monitoring.**		
PacifiCorp	Yes	Regarding requirement in 5.1.5: This requirement is very vague - "major voltage sensitive area" is not a defined term. I Recommend it be revised to reference UVLS programs that are required to maintain compliance with the TPL standards, or possibly place a MW limit of 300 or more MW of load shedding to qualify for consideration.
Response: Thank you for your comment. **Refer to the Guidelines and Technical Basis Section for Requirement R5.** **"Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could**		

Organization	Yes or No	Question 3 Comment
be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).”		
Puget Sound Energy	Yes	a) R3 could refer to R4 (see R4) in regards to details for each triggered FR. b) R8 discusses "continuous data and storage", whereas R11 states that data shall be retrievable for 10 days (presumably following an event), as data retention for longer is expensive and unrealistic. The statements in R8 and R11 may need clarification as to how much data needs to be held in memory before it is overwritten. Data from a catastrophic event may fill a recorder much more quickly than baseline data.
Response: Thank you for your comment. **The Drafting Team believes that the reference in Requirement R4 to Requirement R3 is adequate.** **Please refer to the Rationale for Requirement R11. The Drafting Team concurs that longer data retention periods are unrealistic. Requirement R11, Part 11.1 was not revised. As written, Part 11.1 limits the amount of data storage required to 10 days. The Drafting Team does not believe that additional clarifications are necessary.**		
Bonneville Power Administration	Yes	BPA believes the authority and responsibility for installing Adequate FR, SER, and DDR equipment must be left to the individual TOs and GOs. These are the parties who will fund these, who know the system best and who will ultimately be responsible for the analysis of system events. It is appropriate that the Responsible Entity request desired locations for this equipment but the final siting decisions must be left to the Owner. Transmission and Generation Owners have long known the value of accurate and comprehensive disturbance monitoring for the purpose of system event analysis. BPA believes it is presumptive to assume that this new methodology for FR and SER placement will provide adequate data for system event analysis. Out of necessity most Transmission and Generation owners have already developed proven strategies for disturbance monitoring on their systems. BPA believes this standard should require Entities to develop their own methodology for monitoring. BPA believes Requirements 11.3, 11.4 and 11.5 go too far in stipulating the file format and naming

Organization	Yes or No	Question 3 Comment
		convention for event data submissions. This is in direct conflict with the DMSDTs' statement: "The standard deals with "what" data is recorded, not "how" it is recorded." File formatting is an administrative detail and does not warrant regulatory scrutiny. BPA does not believe this Standard should require the Transmission Owner (TO) to notify other owners of BES equipment of their compliance responsibility with respect to this standard. As written, the notification requirement in R1.2 places an undue compliance risk on TOs and should be removed. BPA also believes the rationale of R3/M3 is a little flawed (if more than one GSU source is connected to the bus then excluding 4 won't allow direct derivation of total fault current on the bus. This would be indirectly derived by comparison of the fault study results.
Response: Thank you for your comments. **Because of its wide-area view, the Responsible Entity is most suited to determine the locations for DDR. Requirement R11, Parts 11.3, 11.4, and 11.5 ensure a consistency in data to facilitate evaluation and analysis. Requirement R3 for FR stipulates data "to determine" the electrical quantities. If an entity can calculate the quantities using other data, that is sufficient for this standard.**		
NIPSCO	Yes	R3 , GSU transformers are excluded based on the Drafting Team's assumption that a fault on the transmission system would be captured by FR data on the Transmission System equipment (line, bus terminals) which is an accurate assumption except for faults on the bus itself. In certain configurations where multiple GSU units terminate into a single Transmission Bus, it is uncertain if this could indeed be calculated as stated by deciphering the contribution from various units. As stated in the current draft of PRC-002-2 Pg 39 of 46 top of page, current calculations would not be required from the GSU terminals of each generator since they can be readily calculated if needed, which is not an accurate statement in all configurations. This leaves what could be a substantial gap for bus faults or for configurations where multiple units of different sizes terminate on separate terminals of the transmission bus. Example would be a large Transmission Substation with a breaker and half configuration with 4 GSU units all terminating on separate terminals into the

Organization	Yes or No	Question 3 Comment
		transmission bus. These units could be of different size and fuel source (Coal units, gas turbines, etc) all terminating to the same transmission bus leaving a substantial gap in FR recording data since the only thing that will be captured is the aggregate of the generation through calculation for external faults, and only simulated data for bus faults. Generators are typically the most significant contributor to transient and sub-transient local fault current at or near larger generation facilities, and also the most susceptible cause of cascading which may result from instability following a system disturbance. Therefore, this requirement would not provide the required data to decipher problem areas on specific generators that may have truly been the root cause without extensive simulation of data using, what would then be, calculated empirical data, not real captured data. This exclusion only appears beneficial for external close in faults and configurations where either a single GSU is connected to the transmission system or a single collector bus with an aggregate GSU source from many of the same units are connected to a Transmission Bus. For the purposes of the standard, exclusions should not be granted to generation terminals since it would result in a discriminatory practice. All significant sources of fault current on an applicable BES Transmission Bus should be deemed equally important for capturing FR data and the only exclusions should be to terminals or elements which only provide load.
Response: Thank you for your comments. **FR data for bus faults is obtainable by FR triggers set to see the bus faults. For the example described with multiple GSU units terminating on separate terminals at a BES bus, calculated data would be used to determine the electrical quantities specified.**		
Lincoln Electric System	Yes	As currently written, LES is having difficulty following Attachment 1 due to the confusing references. At a minimum, recommend clarification be added as to what “list” each step in the attachment is referring to, considering that the “list” may change throughout the steps. For example, in Step 3, does the “list” in the second sentence refer to the list created in the first sentence, or is it referring to the “list” created in Step 2? Or should the second sentence in Step 3 be moved to Step 2?

Organization	Yes or No	Question 3 Comment
		Without additional clarification, it is difficult for an entity to determine how to proceed through the steps in the attachment, especially Step 7.
Response: Thank you for your comment. **The steps of Attachment 1 are sequential. An entity should follow them in order to complete the requirement. For example, the list of BES Buses developed per Step 2 is a reduction of the list developed in Step 1. Step 3 further refines the list of BES buses. Step 7 provides possible scenarios and only one will apply depending on the result of Step 6.**		
Xcel Energy	Yes	In response to Xcel Energy's comment in the previous ballot, the Drafting Team states that changes were made in Step 7 and 8 to recognize that requiring close busses have date recording equipment would not provide significant value. However, a review of these steps in the redline document does not show that changes were made to address this issue. The Drafting Team did add language in the Rationale box under Requirement 3 addressing busses serving only generators but it is not clear how this rationale statement is made part of the requirements. Because of the perceived conflict in the rationale compared to the requirement, Xcel Energy is voting negative on the standard. We believe that the rationale statement is correct but the change has not been implemented in the requirement and associated calculation. Please correct this oversight. Thank you for your effort on this issue.
Response: Thank you for your comment. **Requirement R3 addresses "FR data to determine…". Because quantities can be determined (i.e. mathematically calculated from other data), for electrically close buses, recording capability would not be needed on each bus. In order to help Drafting Teams expand on the concepts and intent of the requirements, rationale boxes were added to the standard. The rationales are designed to provide entities and auditors with the intent of the Drafting Team during the development of the standard. The rationales are moved to the Guidelines and Technical Basis Section of the standard once the standard is approved and will remain there.**		
Ameren	Yes	To help assure the ability to meet the 90-day time limit for Requirement R12, we believe that it may be necessary to have at least one spare of each model of PMU installed on the system on hand for use in replacing a failed unit in a timely manner.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment.		
Independent Electricity System Operator	Yes	We generally agree with all the proposed changes. However, the addition of the phrase “and implement the reevaluated list of BES buses as per the Implementation Plan” to Part 1.3 and the phrase “and implement the reevaluated list of BES Elements as per the Implementation Plan” to Part 5.4 is unnecessary which makes the requirement out of date over time. The implementation timeframe should be stipulated in the Implementation Plan, not in the requirements. We suggest the SDT to make this change, which can be regarded as not having material impact to the intent of the concerned requirements and hence may not require another round of successive balloting if this draft receives 2/3 majority support at the ballot.
Response: Thank you for your comments. **On Page 4 of the Implementation Plan under Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11: compliance with the re-evaluated list is addressed. The reference to the Implementation Plan in Requirement R1, Part 1.3 and Requirement R5, Part 5.4 was added for clarity in response to comments received from previous postings.**		
American Electric Power	Yes	AEP recommends modifying R2-R4 and R6-R11 to clearly exempt data lost due to an equipment failure properly identified per R12. Our concern on this matter has led, in part, to our decision to vote negative on the standard. R3: The Application Guide implies that GSU leads are not considered lines for this standard. The requirement should be revised to clearly indicate this. Similarly, station service or reserve transformers should likewise be explicitly excluded. Our concern on this matter has led, in part, to our decision to vote negative on the standard. As stated in our previous comments, AEP recommends modifying R3 so that only three of the four currents are required to be recorded. Since the fourth current can be calculated by the other three, there is no reliability impact for recording only three currents. The Drafting Team responded by saying “The Rationale Box for Requirement R3 explains the need for the three phase currents and the residual or neutral current”, however it is not necessary to monitor all these quantities to

Organization	Yes or No	Question 3 Comment
		provide the data mandated by R3.It is clear from the rationale section for R3 that GSU transformers are excluded from the requirement. However, R3 states "Each TO *and GO* shall have FR data...for the BES Elements it owns connected to the BES buses...". The requirement should be revised to align with the exclusion provided stated in the rationale section. R12: We see no reliability benefit in sending all CAP's to the Regional Entity, and recommend revising it in consideration of Paragraph 81. Rather, it should be acceptable to only require the TO/GO to develop and execute a CAP and to make this information available to the RE within 30 calendar days of a request.R2: We believe that it is clear that the TO/GO must have SER data for circuit breaker position as it related to the following BES elements connected to a BES bus; BES Transmission Lines, BES Transformers and BES Generator feeds. Does this Requirement also apply to circuit breakers/circuit switchers that serve BES shunt capacitors/reactors?

Response: Thank you for your comments.

Data capability lost due to equipment failure is addressed by Requirement R12 and does not need to be explicitly referenced in other requirements.

Regarding the handling of a GSU and its leads, refer to the Rationale for Requirement R3. Also, as per Requirement R3, the quantities can be determined (i.e. mathematically calculated from other data). The Rationale for Requirement R3 was previously revised to replace derivable with determinable. GSU low side voltages are below 100kV. In order to help Drafting Teams expand on the concepts and intent of the requirements, rationale boxes were added to the standard. The rationales are designed to provide entities and auditors with the intent of the Drafting Team during the development of the standard. The rationales are moved the Guidelines and Technical Basis Section of the standard once the standard is approved and will remain there.

The Drafting Team discussed the submission of Corrective Action Plans to the Responsible Entity. It was decided to have the CAPs just go to the Regional Entity because the Regional Entity is in a better position to have an overview of the data recording capability for its entire area. The timetable is discussed in the Rationale for Requirement R12. Requirement R2 applies to all breakers connected to the BES buses defined in Requirement R1.

Organization	Yes or No	Question 3 Comment
ISO New England	Yes	The triggers described in the first two bullets of Requirement 8.2 should be clarified to include the duration that the Standard Drafting Team based them on. Otherwise, the data produced may be inconsistent across interconnections and may be subject to different interpretations. Requirement 11.3 should be deleted because providing the data in formats other than ASCII Comma Separated Value (.CSV) should be allowed. In other words, the requirement should not prescribe a data format.
Response: Thank you for your comments. **Information from the Drafting Team members and industry indicated that there are very few triggered DDR recorders in service. Most DDR recorders are continuous not needing triggering. DDR data capture is for slowly evolving system conditions. Entities owning triggered DDR recorders would have the trigger durations set appropriately, and the duration of triggering quantities was judged not to be a problem. The Drafting Team did not think it necessary to add trigger duration to the requirement. Regarding Requirement R11, Part 11.3, refer to the Rationale Box for Requirement R11:** **"SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve a common data format for event records, enabling the use of software tools for analyzing the SER data."**		
City Utilities of Springfield, Missouri	Yes	City Utilities of Springfield, Missouri supports the comments submitted by the SPP Standards Review Group and the following additional suggestions: Regarding R1 and Attachment 1: We continue to believe the Attachment 1 fault MVA threshold established in R1 to identify potential buses from which to pick locations for FR (and SER) data is too low. All of the BES buses on our system have fault MVA above the 1500 MVA threshold and no reduction to the number of buses on our list occurs by application of the steps outlined in Attachment 1. Given the size of our utility, it seems odd to us that all of our buses are considered "key" to the BES. Regarding R3: We continue to believe it is not necessary to be able to determine the electrical quantities associated with every element connected to a bus for a fault on

Organization	Yes or No	Question 3 Comment
		one element of the bus. Rather, we believe that if devices are present to capture sufficient data necessary to determine the required quantities associated with the "faulted" element, that is sufficient for fault analysis. We believe it is sufficient for an entity to be able to determine fault location, fault type, cause of relay operation and the currents and voltages required by this proposed Standard associated with the faulted element for the purposes of Fault Recording. This seems to meet the intent voiced in the "Rationale for R3". Please clarify the purpose of requiring electrical quantities be determined for all elements connected to a bus for a fault on any element of that bus if the required quantities associated with the faulted element can be determined. Also, it seems to us that comments regarding determining correct operations of the protection system within the proposed Standard and guidelines document are out of scope for this Standard and are already covered in other NERC Standards, PRC-004 specifically. Regarding R4:We appreciate the SDT revising the total record length in the first bullet under R4.1 from at least 32 cycles to at least 30 cycles. Regarding R10:We appreciate the SDT's clarification that the time synchronization pertains to the device clock.
Response: Thank you for your comments. **Refer to the responses to the SPP Standards Review Group.** **R1: The 1,500 MVA three phase short circuit was chosen based on input from across the continent and the Drafting Team's judgment. The resulting list of BES buses will not be burdensome for implementation.** **R3: Requirement R3 specifies the quantities "for each triggered FR…". Electrical quantities determined (i.e. mathematically calculated from other data) for all Bulk Electric System Elements connected to a bus helps explain System response to a fault.**		
Luminant Generation Company, LLC	Yes	Luminant is specifically concerned about the administrative requirements in the standard related to reporting formats. Luminant does not disagree with the desire or benefit of standardized reporting, however, we believe specific data and reporting

Organization	Yes or No	Question 3 Comment
		formats do not belong in the standard requirements. The ERO already has the authority to request data and reports in specific forms or formats. (1) Requirement R11, subsections 11.3, 11.4 and 11.5 includes prescriptive details regarding data recording and reporting. The goal of the standards development process is to develop Results Based Standards. We reiterate our concern that these items are completely administrative in nature and are not results based. An entity could make a typo in formatting or when naming a file and be non-compliant with the requirement. These requirements should be removed from the standard or relocated to reference documents. (2) Requirement R11, subsections 11.4 and 11.5 reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. Inclusion in a reference document seems to provide a better location to document specific details on requested data and can provide a more effective mechanism for revising these details at a later date in regards to the data reporting. The requesting agency has the right to ask for data in any prescribed format they desire, but this should not be identified in the standard. (3) Requirement R11, subsection 11.4 specifically references “IEEE C37.111-2013”. We reiterate our previously submitted comment on the version specification. The SDT response focused on conversion software. Some older DFRs that effectively capture the needed data may not meet this requirement for the “2013”. Software updates may not always be reasonably accomplished with equipment, service contracts or other factors. This 2013 mandate is administrative in nature and does not contributed to a results based standard nor improve BES reliability. This version requirement should be revised to allow for any versions that the entity has access to that supports the recording and report requirements.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. **1. Because standardized formats result in the expeditious and effective analysis of System Disturbances they were included in Requirement R11. Having the formats in the standard make them enforceable.** **2. IEEE Standards are referenced to ensure consistency and adherence to them is enforceable as they are part of the standard.** **3. Requirement R11, Part 11.4 was revised prior to the last posting to remove the 2013 requirement. "11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later."**		
RelliabilityFirst	Yes	ReliabilityFirst votes in the Affirmative and believes the standard helps ensure that adequate data is available to facilitate analysis of Bulk Electric System (BES) Disturbances. This standard also removes the "fill in the blank" aspects of the old PRC-002 and PRC-018 standards. ReliabilityFirst offers the following comments for consideration: 1. Requirement R1, Part 1.3 - Requirement R1, Part 1.3 references an "Implementation Plan" and it is unclear to ReliabilityFirst how this will be enforced. The posted PRC-00202 Implementation Plan only speaks to the initial identification of buses and does not address the re-evaluation of the list. Furthermore, a NERC Reliability Standard should not have requirements which reference documents which are outside of the standard. ReliabilityFirst suggests this reference to Implementation Plan be removed from Part 1.3.
Response: Thank you for your comment. **Compliance with a re-evaluated list is addressed on Page 4 of the Implementation Plan.** **The reference to the Implementation Plan was added for clarity in response to comments received from previous postings.**		
Oncor Electric Delivery LLC	Yes	We recommend the following language from the R7 to be used in R3 "Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, the Generator

Organization	Yes or No	Question 3 Comment
		Owner is still responsible for the provision of this data." As currently written the rationale in R3 places the burden on the TO when the GO should be held responsible. It is not a "given" that the TO FR is already monitoring GO generator breakers due to the legal deregulation splitting of asset ownership and monitoring isolation between TO/GO interfaces. In regards to R2 and R11.3 we recommend a similar provision for Legacy devices be provided as done in R8. We recommend the following verbiage be added:"If the FR equipment was installed prior to the effective date of this standard and is not capable of SER recording, Breaker position must be monitored by a digital element in the FR."Oncor recommends the following verbiage be added after the last sentence in the Guideline for Requirement R6 and R7: "The R6.3 and R7.3 assumption is that there is a balanced 3 phase system so calculating 3 phase power based on single phase voltage and current quantities is acceptable"
Oncor Electric Delivery LLC	Yes	We recommend the following language from the R7 to be used in R3 "Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data." As currently written the rationale in R3 places the burden on the TO when the GO should be held responsible. It is not a "given" that the TO FR is already monitoring GO generator breakers due to the legal deregulation splitting of asset ownership and monitoring isolation between TO/GO interfaces. In regards to R2 and R11.3 we recommend a similar provision for Legacy devices be provided as done in R8. We recommend the following verbiage be added: "If the FR equipment was installed prior to the effective date of this standard and is not capable of SER recording, Breaker position must be monitored by a digital element in the FR." Oncor recommends the following verbiage be added after the last sentence in the Guideline for Requirement R6 and R7: "The R6.3 and R7.3 assumption is that there is a balanced 3 phase system so calculating 3 phase power based on single phase voltage and current quantities is acceptable"

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. **The suggested wording was added to the Rationale for R3.** **PRC-002-2 deals addresses "what" data is recorded, not "how" the data is recorded. It is up to the TO or GO, as applicable, to make provisions to capture SER data. SER data recording is not as parameter dependent as DDR (requirement R8).** **The sections in the Guidelines and Technical Basis Section for Requirements R6 and R7 address balanced operating conditions as stated on Page 38 (Guidelines and Technical Basis Section) of the standard. The Drafting Team does not believe that further clarifications are necessary.**		
Texas Reliability Entity	Yes	1) Requirement R12: Texas Reliability Entity, Inc. (Texas RE) reiterates the concern raised during the previous ballot period that the Regional Entity is the appropriate entity to receive a TO or GO's Corrective Action Plan (CAP) as written in this requirement. Based on the language in the "Rationale for Functional Entities," it appears that either the Planning Coordinator (PC) or the Reliability Coordinator (RC) should be the recipient of the CAP. The Rationale for Functional Entities states that the "The Responsible Entity - the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection - has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required." Since the PC or RC is responsible for determining which BES Element data is needed, then they arguably need to know when there is a failure of the recording capability for that data and what the CAP is to restore the recording capability. The PC or the RC are in a better position to evaluate whether a CAP has been implemented. Therefore, submitting the CAP to the PC or RC is more appropriate than submitting the CAP to the Regional Entity as it will likely enhance reliability. Texas RE recommends the SDT change the second bullet under Requirement R12 from the "Regional Entity" to the "Responsible Entity." 2) Requirement R1 VSLs: The language within the first "OR" of the Lower VSL states the TO was late by 30 calendar days or less for Parts R1.1 and 1.3. Texas RE has two concerns regarding the language: A) Texas RE is not clear on what the VSL criteria of 30, 60, 90 or more than 90 calendar days is measuring against. Would the SDT please

Organization	Yes or No	Question 3 Comment
		explain what the TO would be late for since Requirement R1.1 has no time criteria? B) Texas RE requests the SDT consider whether the VSLs for re-evaluating all BES buses at least once every five calendar years for Part R1.3 is appropriate. For an evaluation that is deemed sufficient to be performed at a frequency of every five years, it would seem that being late by 30, 60, 90 or 90-plus days might not be the correct timeframe for assessing the severity of a violation. Texas RE suggests assigning criteria on quarters. So that a Lower VSL would be late by one quarter, Moderate VSL would be late by two quarters, High VSL would be late by three quarters and Severe VSL would be late by four quarters based on the previous evaluation date.
Response: Thank you for your comments. **1. The Drafting Team discussed the submission of Corrective Action Plans to the Responsible Entity. It was decided to have the CAPs just go to the Regional Entity because the Regional Entity is in a better position to have an overview of the data recording capability for its entire area. The timetable is discussed in the Rationale for R12. Requirement R2 applies to all breakers connected to the BES buses defined in Requirement R1.** **2. A. The Implementation Plan for Requirement R1 stipulates that an entity shall be 100 percent compliant within six months after approval. The 30, 60, 90 days refers to days past the 100 percent compliance date.** **2. B. Requirement R1, Part 1.3 is intended to consider changes in Disturbance monitoring necessitated by System changes. The VSL time periods are appropriate for the intention.**		
City of Tallahassee, TAL	Yes	TAL believe that disturbance monitoring though good for event analysis will provide little improvement in the reliability of the BES. Disturbance monitoring should be recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
City of Tallahassee	Yes	TAL believes that disturbance monitoring though good for event analysis will provide little improvement in the reliability of the BES. Disturbance monitoring should be

Organization	Yes or No	Question 3 Comment
		recommended to utilities through guidelines instead of through mandated standards. The amount of additional work required by utilities to install, maintain, and, likely the most demanding task, documentation/maintenance of compliance records with this proposed standard will not offset the small benefit seen by the collection of disturbance data.
Response: Thank you for your comment. **A guideline will not ensure that there is adequate data available for event analysis continent-wide; guidelines are unenforceable. (Same comment for Question 2).**		
American Transmission Company LLC	Yes	ATC recommends correcting the typographical error in Requirement 11.2. The text should read, “Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.”
Response: Thank you for your comment. **The Drafting Team used hyphenated dates throughout the standard.**		
CenterPoint Energy Houston Electric	Yes	As stated in comments previously submitted regarding requirement R10 in conjunction with requirement R2, CenterPoint Energy continues to propose that UTC time synchronized DFR and DDR data is the final analysis tool and that, given the infrequent nature of wide area events, breaker state change SER data obtained from EMS systems provides adequate resolution for the initial phases of event analysis investigation. In CenterPoint Energy’s opinion the SDT has not provided sufficient justification to require such high resolution data in regards to breaker open/close SER data. While CenterPoint Energy recognizes this fine level of data may enhance analysis of a wide area event, the 2003 Blackout as well as other analysis’ of more recent wide area events indicates that this level of data is not critical to performing an accurate event analysis. CenterPoint Energy is concerned that this requirement may lead to applicable entities having to install additional SER equipment, communications infrastructure, or data gathering devices to be used only in the rare

Organization	Yes or No	Question 3 Comment
		event that a wide area system disturbance occurs. Therefore, CNP recommends removing SER data from R10.
Response: Thank you for your comment. **With the improvements in technology since the 2003 Blackout, Disturbance analysis should take advantage of those for refinements and the development of more accurate and precise findings. The existing standards do not mandate the collection of the needed data for event analysis. The data mandated by PRC-002-2 can also be used in the refinement of models. The North American SynchroPhasor Initiative (NSAPI) has shown that the use of DDR date can dramatically improve modeling to reflect real system responses to disturbances. DDR data may also be used for Real-time system operating management, especially in making restoration decisions.**		
Liberty Electric Power LLC	Yes	Disturbance monitoring Requirements should be established by the Regional Entity based on their overview of the BES, and monitoring equipment installed and maintained by the TO's to meet the requirements. GO's shoeuld not be included in the standard.
Response: Thank you for your comment. **It is important for event analysis to know generator behavior during the event. The Transmission System influences generation, and generation influences the Transmission System.**		
Director, Reliability Compliance	Yes	City of Austin dba Austin Energy (AE) does not agree with this standard as a whole because it is too prescriptive and unnecessary in the ERCOT Region. Regional requirements for the ERCOT Region regarding disturbance monitoring equipment exist in the ERCOT Nodal Operating Guides, Section 6.1. (http://www.ercot.com/mktrules/guides/noperating/cur). Existing requirements provide sufficient data for disturbance monitoring and analysis. AE recognizes, as the SDT pointed out, the ERCOT requirement is not a NERC Reliability Standard. However, AE disagrees with the SDT’s comment that the ERCOT requirements are not enforceable. Entities in the ERCOT Region must comply with the ERCOT requirements or face penalty by the Public Utility Commission of Texas (PUCT). Further, compliance

Organization	Yes or No	Question 3 Comment
		with ERCOT requirements is monitored and enforced by Texas Reliability Entity, Inc. (Texas RE). AE suggests the SDT consider a regional variance for the ERCOT Region, because sufficient requirements already exist.
Response: Thank you for your comments. **There must be uniformity continent-wide and in NERC for standards, and PRC-002-2 sets the foundation for Disturbance monitoring.**		
Tacoma Power	Yes	Although we agree focusing on “what” data rather than “how” data is a good idea, Measures M2 and M3 parts (1) and (3) are not consistent with that philosophy. Documented design specifications or station drawings are not evidence that the owner actually has SER/FR data; these documents are simply evidence of “how” the data might be captured rather than “what” data is actually being captured. In order to address the inconsistency between the requirement and the measure, the term “recording capability” should be inserted after the word “data” in Requirements R2 and R3. As currently written, this standard has a zero defect approach. A single missing piece of data is not a threat to the BES when analyzing historical events. In addition to the PRC-002-2 required recordings, most utilities have been installing microprocessor based relays with data recording capabilities. Requirement R5, Part 5.2.2, does not use the word ‘additional,’ but the Rationale for R5 does. If a Responsible Entity has 3,000 MW of historical simultaneous peak System Demand, are they required to have (at minimum) 1 or 2 locations with DDR? Requirement R5, Part 5.4, requires the Responsible Entity to implement the reevaluated list of BES Elements. However, the discussion in the Rationale for R5 says that the Transmission Owner and Generator Owner are responsible for implementation. It is understood that the Rationale for R5 is what is intended. Requirement R5, Part 5.4, ought to be amended to be consistent. In Measurement M9, it appears that the text “(R9, Part 9.1)” may be missing.

Organization	Yes or No	Question 3 Comment
		In Requirement R11, Part 11.2, change "...unless and extension..." to "...unless an extension..." Requirement R11, Part 11.1, will likely drive (1) automatic event retrieval from relays used for FR/SER, (2) restriction of event triggers in relays (to the detriment of the entity's other business objectives as they try to assure compliance for all scenarios), and/or (3) installation of dedicated FR equipment (or new relays) with large buffers. Buffers in many types of relays used for FR/SER could easily be overwritten within 10 calendar days, depending upon what event triggers are set up and power system conditions. It seems like the implementation plan for Requirements R2-R4 and/or R6-R11 in response re-evaluated lists from Requirement R1 or R5 should be included in the body of the standard. Implementation Plans are normally valid only for the initial phase-in of a standard (or new version of a standard). The response to a re-evaluated list is an ongoing activity.

Response: Thank you for your comments.

Measures M2 and M3 indicate the choices an entity has for showing compliance with the related Requirements which includes "how" the data is captured.

The sub-Parts under Requirement R5, Part 5.2 are an "and" statement. DDR coverage would be required for one BES Element, and one additional Bulk Electric System Element per 3,000 MW of peak System Demand.

Requirement R5 pertains to the Responsible Entity, and Requirement R5, Part 5.4 has the Responsible Entity notifying owners. The Rationale is intended to be an explanation of Requirement R5.

The reference to Requirement R9, Part 9.2 in Measure M9 was revised to add (R9, Part 9.1; R9, Part 9.2) to Item (1) of Measure M9.

Requirement R11 Part 11.2 was revised previously to "unless an extension" ("and" was corrected to "an").

Refer to the Rationale for Requirement R11.

Organization	Yes or No	Question 3 Comment
"Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary." **The reference to the Implementation Plan in the standard was added for clarity in response to comments received from previous postings. A section of the Implementation Plan refers to the re-evaluated lists.**		
Electric Reliability Council of Texas, Inc.	Yes	ERCOT generally agrees with all the proposed changes and proposes some additional clarifications as provided below: o The addition of the phrase "and implement the reevaluated list of BES buses as per the Implementation Plan" to Part 1.3 and the phrase "and implement the reevaluated list of BES Elements as per the Implementation Plan" to Part 5.4 is unnecessary and makes the requirement out of date over time. The implementation timeframe should be stipulated in the Implementation Plan, not in the requirements. o R5.1.4 should be revised to state: One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL). o An additional sub-requirement should be added as R5.1.6, stating:5.1.6 Any one BES Element that has previously demonstrated localized dynamic oscillations. o An additional sub-requirement should be added as R 5.1.7, stating:5.1.7 Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. o Additionally, ERCOT respectfully submits that the RC/PC does not implement the plan, the TOs/GOs do (see paragraph 5 of Rationale for R5.) Accordingly, ERCOT recommends that R5.4 be revised to strike the last phrase as shown below: 5.4 Reevaluate all the identified buses BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2 and notify owners in accordance with Part

Organization	Yes or No	Question 3 Comment
		5.3, and implement the reevaluated list of BES Elements as per the Implementation Plan. o Requirement R8 should include a trigger for dynamic oscillations with less than 5% damping (whether local or inter-area).Requirement R8.2 should be reworded to identify triggers that are appropriate for the reasoning for the DDR identified in R5. For example, it is more appropriate for the trigger to be based on voltage for voltage sensitive areas. Gen locations would most likely trigger off (at least) frequency. ERCOT also recommends that the SDT consider the appropriate trigger for angular stability locations. For ERCOT, the off nominal frequency trigger should be set at 59.4 and 60.6 for ERCOT. This would give some additional bandwidth before entering 1st stage UFLS and catch the high frequency setpoint where generators should not trip off within 9 min. Additionally, the undervoltage trigger should be set consistently with that of the UVLS in the area. To set the trigger below the UVLS scheme would not utilize the equipment appropriately and the recording should be utilized to capture any UVLS event that would actually activate.

Response: Thank you for your comments.

The reference to the Implementation Plan in the standard was added for clarity in response to comments received from previous postings. A section of the Implementation Plan refers to the re-evaluated lists.

The wording in Requirement R5, Part 5.1.4 was revised as such for the previous posting.

Regarding adding additional sub-Parts, an entity can capture data for any Bulk Electric System Element that has exhibited extraordinary behavior during System Disturbances. Language such as “major transmission interfaces” was removed from previous versions because stakeholders felt that it was ambiguous and unenforceable.

Requirement R5 pertains to the Responsible Entity, and the Responsible Entity has implementation responsibilities. The TO and GO are involved with the implementation of Requirement R5. The Implementation Plan addresses the re-evaluation.

Information from the Drafting Team members and industry indicated that there are very few triggered DDR recorders in service. The triggers listed in the requirement will not be expanded.

Organization	Yes or No	Question 3 Comment
PPL NERC Registered Affiliates		These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. We agree that DDR data should be obtained for the transmission lines from generation plants as listed in requirement 5, but not that GOs are the parties that should collect this information (R7). There has been much discussion between the North American Generator Forum (NAGF) and the Disturbance Monitoring Standard Development Team (DMSDT) regarding assignment of responsibility for monitoring disturbances, and we believe GOs should be excluded for the following reasons:- TOs interpret and use DME data; GOs do not. - TOs generally have wide-ranging arrays of DME, continuous recording/storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. - DDR data collected on the TO's side of the generation plant battery limits would be the same as that measured on the GO's side. - Disturbances are more likely to originate in the transmission system than in generation plants (as was the case for the Northeast blackout of 2003), and responsibility should rest with the party causing the need for monitoring. We understand that duplication of equipment is not mandated - a GO could contract with it's TO to supply DDR data. It may not be possible to negotiate such agreements, however, due to the impracticality of transferring compliance responsibilities and the GO risk exposure if TOs commit to sharing data but not to achieving PRC-002-2 compliance. The NAGF attempted to find common ground with the DMSDT by recommending that the standard should at least state that TOs are responsible for providing DDR data if they already have such equipment at plants, but this request was evidently rejected, and R7 as presently written is therefore likely to lead to widespread wasteful duplication of equipment and effort. The least-total-cost approach should be followed in obtaining the expected reliability benefits, and we believe that centralizing DME with TOs makes more sense than splitting the

Organization	Yes or No	Question 3 Comment
		responsibilities between involved entities (TOs) and those who merely hand-over recordings (GOs) for further analysis. The entire subject of DME should be a TO matter and applicable to the TO's DME equipment that is already installed.
Response: Thank you for your comments. **GOs can use DDR to observe a generator's response to slowly evolving System Disturbances. Generator performance is crucial for event analysis, regardless of what initiated the disturbance.** **DDR data collected by the TO will generally be reflective of the entire System contribution. It is important to have DDR data dedicated to monitoring a generator's performance. The GO is responsible for supplying the data and it is up to the GO to determine the best course of action to provide that data.**		
Florida Municipal Power Agency		FMPA believes the standard, as written, places an onerous burden upon small Transmission Owners and Planning Coordinators that may only have one or two BES buses. The language and methodology effectively guarantee that such small entities must install equipment and report data under the standard. In R1, FMPA believes the Responsible Entity should be the one applying the methodology in Attachment 1 instead of the Transmission Owner. It is more appropriate from a Functional Model perspective to have the Planning Coordinator, for example, obligate the Generator Owner to the requirements that follow. Also, the Responsible Entity has the wide area view that will allow for more dispersed equipment, and lessen the potential for duplicative coverage. The Responsible Entity may need to use data from the Transmission Owners in its area, but once it has the data the formula in Attachment 1 can be followed. There are logical problems, as well as, issues with the inherent tiering between smaller entities and larger entities with Attachment 1.In Step 2, 1500 MVA is too low for small entities with few busses because they are either in remote locations and pose little risk of causing wide-area events or are located near facilities of a large neighbor that drive up the short circuit MVA level of the buses they own. In the latter case, the neighboring facilities would be better candidates for SER and FR data and there would be no value in having additional data from the nearby facilities just because there is a different responsible entity. The main issue hinges upon the

Organization	Yes or No	Question 3 Comment
		fact that the 1500 MVA threshold works well as an initial tool for evaluating large systems with many buses but does not work well as a singular and final compliance threshold (which is what it becomes for small entities). FMPA suggests raising the 1500 MVA criteria in Step 2 to at least 3000 MVA (or higher) for entities with 11 buses or fewer in their system. Step 3, as worded, is confusing because it causes a list of 11 buses to be determined and then causes steps to be skipped if there are 11 or fewer buses, which will always be the case. FMPA suggests replacing in Step 2 the phrase “If there are no buses on the resulting list, proceed to Step 7.” with “If the list has 11 or fewer buses, proceed to Step 7.” and deleting the same phrase from Step 3. Zero is fewer than 11, so we believe this results in what the Drafting Team intended. In Step 7, the reference to Step 3 should be a reference to Step 2. The word “the” should be deleted in the phrase “at least the 10 percent”. FMPA appreciates the SDT comment responses. Unfortunately, these responses do not mitigate the concerns raised in general about the need for the standard versus a guideline. Plus not all of our comments were addressed. Our prior concerns still remain in addition to some additional concerns. SDT Response 1:”The Standard Drafting Team realizes that improvements have been made to Disturbance Monitoring technology since the 2003 Northeast Blackout. That does not guarantee universal implementation, thus necessitating the need for the standard.”--While the SDT may “realize” that improvements have been made over the last decade, the SDT has not provided a risk assessment to quantify the need for a standard versus a guideline recognizing the technology advances and PMU equipment installed through the DOE Smart Grid program over the last decade. A risk assessment would be a beneficial exercise to identify gaps first, as opposed to taking a broad brush approach. It would also provide for more focused impact and faster results.SDT Response 2: “PRC-002-2 addresses “what” data is recorded, not “how” the data is recorded. This approach eliminates the complications that might arise from the technological advances being made to record the data”--The fact that this standard is requiring data vs equipment does not mitigate the fact that equipment will need to be installed which raises a cost recovery concern that needs to be addressed.SDT Response 3: “The Disturbance Monitoring

Organization	Yes or No	Question 3 Comment
		recordings can be used to improve reliability by providing information that can guide operators in better Real-time system management (Real-time system management includes providing information to make BES and facility restoration decisions), and facilitate the evaluation of system performance during and after abnormal system events."--Guiding operators goes beyond the scope of the standard for a number of reasons, but most importantly due to the fact the Time Horizon is "Long Term Planning" and not "Real-time Operations". This raises another concern, which is with regard to the purpose of the standard which now states: "To have adequate data available to facilitate ("event" has been removed) analysis of Bulk Electric System (BES) Disturbances (now upper case)". By removing "event" and capitalizing "Disturbance", which is very broadly defined in the NERC Glossary, this broadens the scope of the purpose of this standard. In R11, there is no defined need for which a Responsible Entity, Regional Entity or NERC can request all SER, FR and DDR data. FMPA believes criteria for making a data request is needed.

Response: Thank you for your comments.

For FR and DDR, the Requirements specify that the electrical quantities can be determined (i.e. mathematically calculated from other data). Equipment is needed to capture only enough data to make the determination. A guideline will not ensure that there is adequate data available for event analysis continent-wide; guidelines are unenforceable. The existing standards do not mandate the collection of the needed data for event analysis. The data mandated by PRC-002-2 can also be used in the refinement of models. The North American SynchroPhasor Initiative (NSAPI) has shown that the use of DDR date can dramatically improve modeling to reflect real system responses to disturbances. DDR data may also be used for Real-time system operating management, especially in making restoration decisions.

The TO is the appropriate entity in R1 because the TO is more familiar with its System's behavior than the Responsible Entity would be.

The 1,500 MVA three phase short circuit value was chosen based on input from across the continent and the Drafting Team's judgment.

The Steps in Attachment 1 are sequential, and achieve the intended result. In Step 7 the commas were removed, and "the" is appropriate.

Organization	Yes or No	Question 3 Comment
A guideline will not ensure that there is adequate data available for event analysis continent-wide; guidelines are unenforceable. **The standard is addressing data for the analysis of BES Disturbances. It is not necessary to specify the criteria for making a data request.**		
SPP Standards Review Group		PRC-002-2Thank you for the clarification in the Applicability Section regarding the use of 'Responsible Entity'. Rationale for R1 - In the 3rd line of the 4th paragraph, the phrase '...into the in force list,...' is used. Shouldn't this be '...into the currently enforced list,...' or '...into the current list,...'? Also, there is a font issue with the inserted sentence. Rationale for R4 - Hyphenate '30-cycle total minimum record length' and '30-contiguous cycles'. Rationale for R11 - Insert a hyphen and a space in '10-calendar day' at the beginning of the 2nd line of the 3rd paragraph. Attachment 1 R1, Step 7-Thank you for the additional clarification in Step 7. Guideline for Requirement R4-Hyphenate '30-cycle record length' in the 4th line of the 1st paragraph and '30-contiguous cycles' in the last line of the 1st paragraph. We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. We would ask that the Drafting Team take into consideration our suggestion to review the language mentioned in reference to the term 'list' in Attachment 1. Our concern at this point would be.... the term presents some confusion in how it's being used in the Steps of the documentation. For example in Step 3, we are not sure what 'list' you are referring to and will this term take on the same meaning as mentioned in the previous Steps (1 and 2)? We would request that you provide more clarity on which 'list' you are referring to and what data should be included in this process.
Response: Thank you for your comments.		

Organization	Yes or No	Question 3 Comment
The wording in the Rationale for Requirement R1 was revised to “currently enforced list”. The Rationales for Requirements R4 and R11 were updated as suggested as well, and the Guidelines for Requirement R4. **The Drafting Team will forward the updated standard to the NERC compliance for inclusion in the final RSAW.** **Regarding the use of “list” in Attachment 1, the lists are sequential as are the steps. For example, the list developed in Step 2 is a reduction of the list developed in Step 1, and so on.**		
DTE Electric Co.		No Comments
Exelon Companies		Requirement R7.1: For clarity consider replacing the first comma with “or” to read “One phase-to-neutral or phase-to-phase or positive sequence voltage......”R7.2: Similar comment - for clarity, consider rewording to replace the commas with “or” to read “The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7.1 or phase current(s) for any phase-to-phase voltages or positive sequence current.” R9.3 requires an output recording rate of at least 30 times per second while the existing NPCC and RFC-CRITERIA-PRC-002-01 requires a recording rate of 6 times per second. Some of the equipment in question was installed in the last several years to meet the RF stadnard/criteria. To meet this new requirement legacy devices will need to be either upgraded or replaced because the higher recording rate will mean they cannot hold a continuous 10 day record. Relaxing the recording output rate to the existing 6 times per second would be sufficient to allow these devices to be compliant with the requirement. The implementation plan for PRC-002-2 includes the following installation requirement for newly-added buses from the re-evaluation process: “Entities shall be 100 percent compliant with a re-evaluated assessed list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated of the list.”The requirement for a 3-yr compliance period will conflict with previously scheduled and planned outage / maintenance cycles . Modifying outage cycles with the time necessary to specify and acquire new

Organization	Yes or No	Question 3 Comment
		equipment will be disruptive. In place of a prescriptive cycle requirement, we propose the requirement be changed to say, Entities shall submit a plan to be 100% compliant with a re-evaluated list from requirements R1 and R5 within 180 days following notification by the TO/Responsible Entity. This plan should include expected completion date(s) justified by outage constraints, equipment lead times and availability. R12 and/or M12 should be modified. We will be using microprocessor relays that also provide protection for SER, FR, and DDR functions. Microprocessor relays that provide protection functions are not allowed to be out of service following a failure for anywhere near 90 days. In addition, we have these relays on all 200kV and above lines. Thus, the failure of one device is not too important from a DME standpoint. Given all this, this requirement is unnecessary for an entity using microprocessor relays as described.We propose that M12 states that protective relaying also used as DME is excluded from this requirement since it is inherent that it will be fixed in less than 90 days. Keeping data to show that relay failures were repaired in less than 90 days is an unnecessary administratve burden and does not contribute to reliable operations. The standard should recognize the varying technologies are used to perform this function and not create administrative burdens.An alternative might be to change the measure to state that if an event occurs that requires RRO or NERC investigation sufficient data was made available to NERC or the RRO to support the event investigation. This will eliminate the need to keep records proving that equipment was fixed in a timely manner.

Response: Thank you for your comments.

The Drafting Team retained the original language of the Requirement R7, Parts 7.1 and 7.2.

The Drafting Team selected the times per second output recording rate in Requirement R9, Part 9.2 based on their experience and industry input.

The three year compliance period in the Implementation Plan for a re-evaluated list was selected by the Drafting Team because it felt three years was adequate to account for maintenance and outage cycles.

Organization	Yes or No	Question 3 Comment
Requirement R12 was included with the intent to ensure that one entity, the Regional Entity, would be aware of the status of the in service recording capability in its area to ensure that adequate recording capability was available.		
Nebraska Public Power District		R11 requires “Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.” It appears a chattering contact could easily fill up an SER or FR device in a matter of minutes or less if it occurs near an event. It is difficult to control or address these issues but they could be a serious impact to the 10 calendar day requirement. Is there a way to minimize this requirement such that event triggers or SERs don’t need to be decreased to help ensure data has less chance of being overwritten? Some microprocessor relays only hold 12 event records so this is more difficult to guarantee data is available this long. In addition it is possible to have more than 12 operations within 10 days during stormy periods. It would seem this case would not allow the data to be available in a relay for the required time. This requirement could force utilities to eliminate many older microprocessor relays on the system that have limited programming and memory capability where the risk for non-compliance could be too great. If this happens then the assertion that many of devices are already on the system that meet the recording requirements is not a generally true statement. Consider removal of this 11.1 requirement since this capability is not entirely under the control of the owner. M1 question: Do we need to just show we sent a notification within 90 days to other owners of BES elements for an identified bus or also show a response? Just showing we sent the notification in good faith is preferred.\ R12 question: The implementation plan states we have 9 months after approval to be 100% compliant for R12. Does this mean we need to be compliant for R12 with elements as they become compliant in R2, 3, 4, 6, 7, 8, 9, 10 and 11 over the implementation time frame? For example, since it could be 4 years and only 50% of elements and their recording capabilities will be compliant how is requirement R12 applied to locations not yet compliant?

Organization	Yes or No	Question 3 Comment
		R4 states: “Trigger settings for at least the following: 4.3.1 Neutral (residual) overcurrent. 4.3.2 Phase undervoltage or overcurrent.” Is it possible to allow additional “OR” statements for 4.3.2?Many relays used for FR will use the phase impedance zone reaches to trigger records. This can clearly define the reach for data to be triggered where defining an under voltage or overcurrent may be more difficult to control the reach. There is some concern with overwriting data in the relays with settings that are less intuitive for controlling how often a device may trigger. We strongly recommend allowing phase distance reaches as trigger points. In past comments it may have appeared to be suggested as overcurrent or distance be included but what was meant was to have both as part of an OR statement. Suggestion: Phase under voltage or overcurrent or distance reach. R12 states “Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.” Should the RE or regional entity be listed in the Applicability section? For some registered entities the Planning Coordinator and the Regional Entity may not be the same. In addition to these comments, we also support the comments submitted by SPP.

Response: Thank you for your comments.

The Drafting Team considered available storage capabilities, and it judged 10-calendar days to be an appropriate time frame.

The intention of Measure M1 is for an entity to have evidence of having made a notification.

Requirement R12 compliance only applies to items that have become compliant.

Requirement R4, Part 4.3 specifies “Trigger settings for at least the following:”. Phase distance triggering can be used in addition to the triggers listed.

The Regional Entity is not responsible for any of the requirements, and therefore does not need to be included in the Applicability section.

Refer to the responses to the SPP Standards Review Group comments.

Organization	Yes or No	Question 3 Comment
CPS Energy		Still feel that the method for determining the busses is too complicated. While we agree that the methodology needs to have consistency, it needs to be made simpler. The spreadsheet is terrible. The examples are difficult to follow and a guide with screenshots needs to be provided to help follow along. For example, how does B3 become a hard-coded example of 64 in both examples when there is nothing in the instructional steps indicating that this value needs to be changed? With hard to follow example, how can we be confident that we are following the procedure correctly to stay in compliance with our own data? The spreadsheet should be simplified to have users enter data without the zero busses, this may help to reduce the number of steps. A better way would be to write a program or something or make the planning coordinators produce the values generated by the spreadsheets. Also, bus fault MVA needs to be defined. Is this based on fault current and nominal voltages or pre-fault voltages? Are there any modeling requirements for generating the fault values? What needs to be recorded for each event - every terminal at a recorder location or just the faulted terminal? If we have microprocessor relays with GPS clock synchronization at every terminal in our system, would that be adequate enough - to capture each fault at the terminal where the fault was located?
Response: Thank you for your comments. **Fault MVA calculations are based on using industry accepted parameters. An entity has to determine the adequacy of its Disturbance monitoring recording capability to capture what data is required.**		
Alliant Energy		Consider revising Requirement R8 so that it refers to continuous recording and storage necessary to meet Requirement R11. Otherwise, it leaves the interpretation open that the user needs continuous unlimited storage of data.
Response: Thank you for your comment. **The Rationale for Requirement R11 addresses your concern.**		

END OF REPORT

Standard Development Timeline

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

Development Steps Completed

1. Nominations for the SAR Drafting Team members were solicited February 26 – March 9, 2007.
2. The SAR was posted for a 30-day comment period March 22 – April 20, 2007.
3. Nominations for the Disturbance Monitoring Standard Drafting Team (DMSDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.
4. The draft standard was posted for a 45-day formal comment period February 2-March 18, 2009.
5. The project was placed into informal development the fall of 2010.
6. The project was placed into formal development January 2013.
7. Nominations for two additional DMSDT members were solicited April 12 – 25, 2013.
8. Three additional DMSDT members were added May 22, 2013.
9. Industry webinars were held May 22, 2013, June 12, 2014, and August 21, 2014.
10. Industry technical conferences were held July 30 - 31, 2013 and August 6 - 7, 2013.
11. The draft standard was posted for a 45-day concurrent comment and ballot period November 1 – December 16, 2013.
12. The draft standard was posted for a 45-day concurrent comment and ballot period May 9 – June 25, 2014 (ballot was extended to achieve quorum).

Description of Current Draft

This is the fourth draft of the proposed standard and is being posted for stakeholder comments and additional ballot. This draft includes the modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with a 10-day Ballot	September, 2014
Final Ballot	October, 2014
BOT Adoption	November, 2014

Effective Dates

See Implementation Plan

Version History

Version	Date	Action	Change Tracking
2.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms (Glossary) used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

When this standard has received ballot approval, the Rationale Boxes will be moved to the Guidelines and Technical Basis Section of the Standard.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

Functional Entities:

4.1 The Responsible Entity is:

4.1.1 Eastern Interconnection – Planning Coordinator

4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator

4.1.3 Western Interconnection – Reliability Coordinator

4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator

4.2 Transmission Owner

4.3 Generator Owner

Rationale for Functional Entities:

When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected.

BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

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

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

Rationale for R2:

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R3:

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Responsible Entity has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Responsible Entity has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Responsible Entity from performing this re-evaluation more frequently to capture updated BES Elements.

The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.

The Responsible Entity must notify all owners of the selected BES Elements that DDR data is required for this standard. The Responsible Entity is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Responsible Entity. Data for each BES Element as defined by the

Responsible Entity must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Responsible Entities, each Responsible Entity will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Responsible Entities. It is intended that each Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R6:

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R7:

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the ‘what’ of DDR, not the ‘how’. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

Rationale for R9:

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

Rationale for R10:

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

Rationale for R11:

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by 10-calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by greater than 30-calendar days.

				owners by greater than 10-calendar days but less than or equal to 20-calendar days.	owners by greater than 20-calendar days but less than or equal to 30-calendar days.	
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified

			number of specified electrical quantities for each BES Element.	Elements and the number of specified electrical quantities for each BES Element.	Elements and the number of specified electrical quantities for each BES Element.	electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was

			5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by	The Generator Owner had DDR data as directed by	The Generator Owner had DDR data as directed by	The Generator Owner failed to have DDR data as directed by

			Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR

			OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	to 110-calendar days after discovery of the failure.	to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

<u>If the list has more than 11 BES buses: SER and FR</u> data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2
Sequence of Events Recording (SER) Data Format
(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]
08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close
08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close
08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open
08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RE (PC | RC)	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses “what” data is recorded, not “how” it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
    a. Only tangible substation or switchyard buses are included.
    b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
    - Electrically distant BES buses or electrically distant from other DME devices

- Voltage sensitive areas
- Cohesive load and generation zones
- BES buses with a relatively high number of incident Transmission circuits
- BES buses with reactive power devices
- Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:
$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings
Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.

- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA”. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires “One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs).” Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area’s response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This

drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating

precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Responsible Entity, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the

data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

Standard Development Timeline

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

Development Steps Completed

1. Nominations for the SAR Drafting Team members were solicited February 26 – March 9, 2007.
2. The SAR was posted for a 30-day comment period March 22 – April 20, 2007.
3. Nominations for the Disturbance Monitoring Standard Drafting Team (DMSDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.
4. The draft standard was posted for a 45-day formal comment period February 2-March 18, 2009.
5. The project was placed into informal development the fall of 2010.
6. The project was placed into formal development January 2013.
7. Nominations for two additional DMSDT members were solicited April 12 – 25, 2013.
8. Three additional DMSDT members were added May 22, 2013.
9. Industry webinars were held May 22, 2013, June 12, 2014, and August 21, 2014.
10. Industry technical conferences were held July 30 - 31, 2013 and August 6 - 7, 2013.
11. The draft standard was posted for a 45-day concurrent comment and ballot period November 1 – December 16, 2013.
12. The draft standard was posted for a 45-day concurrent comment and ballot period May 9 – June 25, 2014 (ballot was extended to achieve quorum).

Description of Current Draft

This is the fourth draft of the proposed standard and is being posted for stakeholder comments and additional ballot. This draft includes the modifications based on comments submitted by stakeholders.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with a 10-day Ballot	September, 2014
Final Ballot	October, 2014
BOT Adoption	November, 2014

Effective Dates

See Implementation Plan

Version History

Version	Date	Action	Change Tracking
2.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the NERC Glossary of Terms (Glossary) used in Reliability Standards are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None

When this standard has received ballot approval, the Rationale Boxes will be moved to the Guidelines and Technical Basis Section of the Standard.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

Functional Entities:

4.1 The Responsible Entity is:

4.1.1 Eastern Interconnection – Planning Coordinator

4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator

4.1.3 Western Interconnection – Reliability Coordinator

4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator

4.2 Transmission Owner

4.3 Generator Owner

Rationale for Functional Entities: When the term “Responsible Entity” is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection ~~–~~has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that~~-~~ all BES buses~~-~~ have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

Rationale for R1: Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment. Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure

sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently ~~in~~ enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

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

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

Rationale for R2:

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R3:

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30~~-~~cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30 ~~-~~cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30 ~~-~~contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 ~~Ensure~~ Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3~~, and~~ to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Responsible Entity has dated evidence (electronic or hard copy) that each Transmission Owner or Generator Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Responsible Entity has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. ~~—~~However, this ~~S~~standard does not preclude the Responsible Entity from performing this re-evaluation more frequently to capture updated BES Elements.

The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.

The Responsible Entity must notify all owners of the selected BES Elements that DDR data is required for this ~~S~~standard. The Responsible Entity is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Responsible Entity. Data for each BES Element as defined by the Responsible Entity must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES

Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Responsible Entities, each Responsible Entity will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Responsible Entities. It is intended that each Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R6:

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the ‘what’ of DDR, not the ‘how’. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

Rationale for R9:

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to~~hat~~ meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

Rationale for R10:

~~NOTE: The rationale for R10 was extensively revised since the last posting. To make reading easier, only the clean version of the language is included here.~~

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

Rationale for R11:

~~NOTE: The rationale for R11 was extensively revised since the last posting. To make reading easier, only the clean version of the language is included here.~~

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date ~~of~~ the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by 10-calendar days or less.	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by greater than 30-calendar days.

				owners by greater than 10-calendar days but less than or equal to 20-calendar days.	owners by greater than 20-calendar days but less than or equal to 30-calendar days.	
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified

			number of specified electrical quantities for each BES Element.	Elements and the number of specified electrical quantities for each BES Element.	Elements and the number of specified electrical quantities for each BES Element.	electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was

			5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by	The Generator Owner had DDR data as directed by	The Generator Owner had DDR data as directed by	The Generator Owner failed to have DDR data as directed by

			Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.
R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.

R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.
R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission

			OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data but less than 100 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after

			to 100-calendar days after discovery of the failure.	to 110-calendar days after discovery of the failure.	to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum

available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2
Sequence of Events Recording (SER) Data Format
(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

~~Center this title =>~~ High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RE (PC | RC)	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).
8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices

- Voltage sensitive areas
- Cohesive load and generation zones
- BES buses with a relatively high number of incident Transmission circuits
- BES buses with reactive power devices
- Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100~~-~~kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_r$, is calculated as a sum of vectors of three phase currents:
$\mathbf{I}_r = 3\bullet\mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings
Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-~~-~~cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30~~-~~-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.

- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA”. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires “One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs).” Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area’s response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the s~~S~~tandard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This

drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating

precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

"Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…"

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

"Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…"

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Responsible Entity, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the

data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a "reasonable" amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2007-11 Disturbance Monitoring

Requested Approvals

- PRC-002-2 Disturbance Monitoring and Reporting Requirements

Requested Retirements

- PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements
- PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting

Prerequisite Approvals

- None

Applicable Entities

- Planning Coordinator
- Reliability Coordinator
- Transmission Owner
- Generator Owner

Revisions to Defined Terms in the NERC Glossary

- None

Background

The Implementation Plan reflects consideration of the following:

1. This standard reflects the need for data, rather than equipment, with the understanding that the data is collected from Disturbance Monitoring Equipment distributed across the BES.
2. A significant amount of sequence of events recording (SER), fault recording (FR), and dynamic Disturbance recording (DDR) capability already exists on the BES. The monitoring requirements in this standard align with industry practices. Therefore, many existing recordings can satisfy the Requirements and Implementation Plan put forth.
3. Fault MVA data is readily available or calculable by the Transmission Owners for the BES buses they own. Therefore, six (6) months is adequate time for generating the list of BES buses following the methodology described in Attachment 1 (for Requirement R1).

4. Responsible entities have the relevant data and information pertaining to the BES Elements requiring DDR and six (6) months is adequate time for working with any affected entities and generating the list of BES Elements.
5. The nine (9) month time period for R12 includes the six (6) month implementation for R1 and R5, and a three (3) month additional time period to make notifications. The nine (9) months for R12 implementation is reasonable for the contents of that requirement.
6. A total percentage of BES buses and BES Elements established in Requirements R1 and R5 respectively are used in the Implementation Plan since these lists are explicitly created and readily available. It is expected that many monitoring requirements will become compliant without significant changes to recording capability.
7. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities.
8. Implementation of Disturbance monitoring recording following changes to the system are addressed by following re-evaluation of the lists as per Requirement R1 and Requirement R5.
9. Implementing SER, FR, and DDR capability may require scheduled outages for both Transmission Owners and Generator Owners. Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant. Meanwhile, Transmission Owners probably will have more BES Elements requiring SER, FR, and DDR and may have to schedule outages across the system. The Implementation Plan takes scheduling outages into account.
10. An entity owning only one (1) identified BES bus, BES Element, or generating unit is allowed six (6) years for implementation to accommodate normal outage schedules.
11. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities.

General Considerations

Each Transmission Owner and Generator Owner subject to PRC-018-1 shall maintain the ability to provide Disturbance monitoring data using current methods required by PRC-018-1 until the entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. As required in PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting, Requirement R1, Parts 1.1 and 1.2, it is expected that the Transmission Owner and Generator Owner will have those functionalities with regard to their current Disturbance data.

Effective Date

The standard shall become effective on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter six (6) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Standard(s) for Retirement

PRC-002-1 Midnight of the day immediately prior to the effective date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Each Transmission Owner, and Generator Owner shall maintain documentation to demonstrate compliance with PRC-018-1 until that entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2 and shall be applicable to an entity's Disturbance monitoring and reporting activities not yet transitioned to PRC-002-2. PRC-018-1 will be retired following full implementation of PRC-002-2 as noted below.

PRC-018-1 Midnight of the day immediately prior to six (6) years after the effective date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for PRC-002-2 Requirements R1 and R5:

Entities shall be 100 percent compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirement R12:

Entities shall be 100 percent compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is nine (9) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10, R11:

Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.

Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.

Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated the list.

Conforming Changes to Other Standards

Where conflicts between the continent-wide standard PRC-002-2 and a regional standard exist, entities should comply with PRC-002-2. Conflicts will be addressed in the appropriate regional standards development process.

- PRC-002-2 Requirement R3 stipulates data must be captured by FR to determine electrical quantities. PRC-002-NPCC-01 Requirement R3 stipulates the recording of those quantities.
- PRC-002-2 Requirement R5 stipulates the capture of DDR data for HVDC. PRC-002-NPCC-01 does not specify HVDC for DDR.
- PRC-002-2 Requirement R8 recognizes DDR that is not continuous, and includes triggering data for DDR that is not continuous. PRC-002-NPCC-01 stipulates that dynamic Disturbance recorders installed after that standard was approved have to be continuous, but does not address legacy devices.

The DMSDT developed this Excel Workbook is designed to assist Transmission Owners in using the Median Method for determining monitoring bus locations for Fault Recording and Sequence of Events Recording on their individual systems.

Instructions for use:

For Transmission Owners Only:

1	Organize your short circuit data in the format shown on the Data Input worksheet
2	Your short circuit data should use three phase short circuit with your selected pre-fault voltage
3	Your short circuit data should be ordered from highest three phase short circuit MVA value to lowest three phase short circuit MVA value for all buses greater than 100 kV
4	Your short circuit data should either eliminate or commonly identify non-real buses, zero buses, pseudo buses, or buses which are used for modeling purposes only, by using a common designation for all these type buses that can be eliminated from the Median calculation. It is most common to identify these non-real buses with the number "0" in the bus coded number field.
5	The Data Input Worksheet is designed to have you copy your properly formatted and sorted three phase MVA short circuit data into rows starting at column A row 6 of the worksheet.
6	Data Input, Col. F, is the most important column, it must have the three phase MVA short circuit data values, sorted from highest MVA to lowest MVA. The MVA values in column F, as sorted from highest to lowest MVA, should include all voltage levels greater than or equal to 100 kV.
7	Once you input all of your short circuit data into the Data Input worksheet starting at Column A Row 6, the values in cells B2, B3 and B4 should all be equal. These values should equal the number of rows of short circuit data that you have input. Copy Cell B2 using Cntrl C, then Paste Value, Special value only, back into Cell B2. This should be the total number of rows contained in the data set.
8	If you have zero numbered buses, or pseudo buses, commonly identified by say a number 0 in the bus coded number column, then you need to determine the number of zero numbered buses that are included in this data set.
9	For you to be able to determine this zero bus coded number, you need to select your entire data set, including the header row, from column / row A5 to G___(last row of data). As an example, if your data contains 100 rows, then your highlighted area for sorting and filtering should be A5 to G105. Then using the sort filter command, turn on Filter
10	Once the Filter is on, go to the bus coded number column, pull down the Filter and select only the zero bus coded number rows. The values in cells B3, and B4 should now be equal and indicate the number of zero numbered buses in your data set.
11	We want to store the zero numbered bus rows (number) into cell B4 as a value. To do this, select Cell B4, hit Cntrl C, then hit paste special, value only. This now repalces the formula in Cell B4 with the value of zero buses in the data set.
12	Now we wish to eliminate the zero bus rows from the rest of our data processing, so in the bus coded number column, we want to filter out the zero bus rows, so we reverse the pull down selection by selecting all rows, except the zero bus coded numbered rows. Leave this Filter in place for the rest of the Median method process.
13	If Cell B4 contains the number zero, then Cell F2 should now contain the 6th value down from the highest short circuit MVA value, and Cell G2 should contain 20% of the Cell F2 value. If Cell F2's value is greater than 1500 MVA this is the new lowest MVA value to be used to determine the number of Median selected buses. If the value in F2 is less than 1500 MVA, then we will use 1500 MVA as the lowest value to select the number of Median buses.
14	If Cell B4 contains a value greater than zero, then Cell F2 needs to be replaced with the MVA value contained in the 11th row, column F of the filtered data set. If the value in F2 is less than 1500 MVA then we will use 1500 MVA as the lowest value to select the number of Median buses.
15	With the Filter still applied to our data set, and zero buses deselected, we will need to use the F2 value to apply as the value used for the MVA column pull down.
16	Using Column F, MVA value pull down, use the Number Filter function, greater than or equal to the F2 value. With this Filter F2 number value applied, now Cntrl C Cell C2, and replace C2 with paste special, value only. This now is the number of buses selected by the Median method.
17	You are Finished!!! The number in Cell C2 indicates the number of Median method selected buses, D2 contains the number of total FR and SOER locations, E2 shows the number of FR / SOER for the Top 10% buses and F2 shows the number of FR / SOER for the Distributed 10% buses.
Notes:	Example 1 (Ex 1 without zero buses) is an additional worksheet shown for a system that does not contains any zero buses. All zero bus entries have been eliminated from the data set.
Notes:	Example 2 (Ex 2 with zero buses) is an additional worksheet shown for a system that contains zero buses. Note for a system that contains zero buses, you must observe the row 11, column F MVA value, and place it into Cell F2. In example 2, this MVA value is equal to 5685 MVA, based on the data set provided.

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	0	1	1	0	0	1500
Median Method	0	1	1	0		1500
Zero Busses	0	0	0	0		
Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**	

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	96	20	10	10	5685	1500
Median Method	64	13	7	6		1500
Zero Busses	0	0	0	0		

Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**
19	NCR ID#	FRCC	230	31120	12397
319	NCR ID#	FRCC	230	23087	9197
52	NCR ID#	FRCC	230	17615	7017
58	NCR ID#	FRCC	230	17039	6788
56	NCR ID#	FRCC	230	16472	6562
23	NCR ID#	FRCC	230	14271	5685
31	NCR ID#	FRCC	230	14018	5584
295	NCR ID#	FRCC	115	27868	5551
294	NCR ID#	FRCC	115	27828	5543
315	NCR ID#	FRCC	230	13810	5502
312	NCR ID#	FRCC	230	12018	4788
51	NCR ID#	FRCC	230	10785	4296
316	NCR ID#	FRCC	230	10616	4229
314	NCR ID#	FRCC	230	10558	4206
320	NCR ID#	FRCC	230	10552	4204
53	NCR ID#	FRCC	230	10342	4120
317	NCR ID#	FRCC	230	10279	4095
302	NCR ID#	FRCC	230	10103	4025
55	NCR ID#	FRCC	230	10076	4014
59	NCR ID#	FRCC	230	9713	3869
304	NCR ID#	FRCC	230	9618	3831
60	NCR ID#	FRCC	230	9605	3826
299	NCR ID#	FRCC	230	9598	3823
303	NCR ID#	FRCC	230	9542	3801
54	NCR ID#	FRCC	230	9110	3629
231	NCR ID#	FRCC	115	14835	2955
215	NCR ID#	FRCC	115	14296	2848
269	NCR ID#	FRCC	115	13212	2632
309	NCR ID#	FRCC	115	12895	2568
230	NCR ID#	FRCC	115	12889	2567
301	NCR ID#	FRCC	115	12781	2546
266	NCR ID#	FRCC	115	12723	2534
238	NCR ID#	FRCC	115	12674	2525
260	NCR ID#	FRCC	115	12674	2525
306	NCR ID#	FRCC	115	11990	2388

271	NCR ID#	FRCC	115	11826	2356
249	NCR ID#	FRCC	115	11049	2201
247	NCR ID#	FRCC	115	10975	2186
246	NCR ID#	FRCC	115	10902	2171
313	NCR ID#	FRCC	115	10868	2165
262	NCR ID#	FRCC	115	10472	2086
242	NCR ID#	FRCC	115	10243	2040
228	NCR ID#	FRCC	115	10089	2010
248	NCR ID#	FRCC	115	9865	1965
217	NCR ID#	FRCC	115	9560	1904
297	NCR ID#	FRCC	115	9521	1896
209	NCR ID#	FRCC	115	9295	1851
243	NCR ID#	FRCC	115	8969	1787
218	NCR ID#	FRCC	115	8926	1778
265	NCR ID#	FRCC	115	8913	1775
232	NCR ID#	FRCC	115	8882	1769
210	NCR ID#	FRCC	115	8875	1768
240	NCR ID#	FRCC	115	8538	1701
239	NCR ID#	FRCC	115	8442	1681
307	NCR ID#	FRCC	115	8397	1673
270	NCR ID#	FRCC	115	8349	1663
272	NCR ID#	FRCC	115	8193	1632
258	NCR ID#	FRCC	115	8000	1593
310	NCR ID#	FRCC	115	7891	1572
211	NCR ID#	FRCC	115	7837	1561
261	NCR ID#	FRCC	115	7822	1558
225	NCR ID#	FRCC	115	7730	1540
234	NCR ID#	FRCC	115	7557	1505
233	NCR ID#	FRCC	115	7543	1502
204	NCR ID#	FRCC	115	7386	1471
259	NCR ID#	FRCC	115	7374	1469
256	NCR ID#	FRCC	115	7314	1457
298	NCR ID#	FRCC	115	7258	1446
244	NCR ID#	FRCC	115	7249	1444
222	NCR ID#	FRCC	115	7204	1435
223	NCR ID#	FRCC	115	7133	1421
263	NCR ID#	FRCC	115	7118	1418
226	NCR ID#	FRCC	115	6989	1392
254	NCR ID#	FRCC	115	6913	1377
267	NCR ID#	FRCC	115	6851	1365
257	NCR ID#	FRCC	115	6846	1364
253	NCR ID#	FRCC	115	6772	1349
245	NCR ID#	FRCC	115	6704	1335
308	NCR ID#	FRCC	115	6571	1309
251	NCR ID#	FRCC	115	6473	1289
241	NCR ID#	FRCC	115	6395	1274
252	NCR ID#	FRCC	115	5556	1107

255	NCR ID#	FRCC	115	5007	997
5	NCR ID#	FRCC	13.2	39503	903
9	NCR ID#	FRCC	13.2	39501	903
13	NCR ID#	FRCC	13.2	39501	903
1	NCR ID#	FRCC	13.2	39492	903
17	NCR ID#	FRCC	13.2	39473	902
6	NCR ID#	FRCC	13.2	39306	899
10	NCR ID#	FRCC	13.2	39304	899
14	NCR ID#	FRCC	13.2	39304	899
2	NCR ID#	FRCC	13.2	39295	898
18	NCR ID#	FRCC	13.2	39276	898
214	NCR ID#	FRCC	115	4498	896
250	NCR ID#	FRCC	115	4329	862
318	NCR ID#	FRCC	13.2	13238	303

Transmission Owner Name	Total Bus Count	Total DFR bus count	Top 10% Bus Count	10% Distributed Bus Count	Median MVA (6th Bus from Top)	New Lowest Median Calc. MVA (20% of Median Value)
Base Values	120	24	12	12	5685	1500
Median Method	64	13	7	6		1500
Zero Busses	24	5	3	2		

Bus Coded Number	**NCR-ID Number**	**Region**	**Bus kV (L-L)**	**Bus 3 Phase Fault--Current (amps)**	**Bus 3 Phase Fault MVA**
19	NCR ID#	FRCC	230	31120	12397
319	NCR ID#	FRCC	230	23087	9197
52	NCR ID#	FRCC	230	17615	7017
58	NCR ID#	FRCC	230	17039	6788
56	NCR ID#	FRCC	230	16472	6562
23	NCR ID#	FRCC	230	14271	**5685**
31	NCR ID#	FRCC	230	14018	5584
295	NCR ID#	FRCC	115	27868	5551
294	NCR ID#	FRCC	115	27828	5543
315	NCR ID#	FRCC	230	13810	5502
312	NCR ID#	FRCC	230	12018	4788
51	NCR ID#	FRCC	230	10785	4296
316	NCR ID#	FRCC	230	10616	4229
314	NCR ID#	FRCC	230	10558	4206
320	NCR ID#	FRCC	230	10552	4204
53	NCR ID#	FRCC	230	10342	4120
317	NCR ID#	FRCC	230	10279	4095
302	NCR ID#	FRCC	230	10103	4025
55	NCR ID#	FRCC	230	10076	4014
59	NCR ID#	FRCC	230	9713	3869
304	NCR ID#	FRCC	230	9618	3831
60	NCR ID#	FRCC	230	9605	3826
299	NCR ID#	FRCC	230	9598	3823
303	NCR ID#	FRCC	230	9542	3801
54	NCR ID#	FRCC	230	9110	3629
231	NCR ID#	FRCC	115	14835	2955
215	NCR ID#	FRCC	115	14296	2848
269	NCR ID#	FRCC	115	13212	2632
309	NCR ID#	FRCC	115	12895	2568
230	NCR ID#	FRCC	115	12889	2567
301	NCR ID#	FRCC	115	12781	2546
266	NCR ID#	FRCC	115	12723	2534
260	NCR ID#	FRCC	115	12674	2525
238	NCR ID#	FRCC	115	12674	2525
306	NCR ID#	FRCC	115	11990	2388
271	NCR ID#	FRCC	115	11826	2356

249	NCR ID#	FRCC	115	11049	2201
247	NCR ID#	FRCC	115	10975	2186
246	NCR ID#	FRCC	115	10902	2171
313	NCR ID#	FRCC	115	10868	2165
262	NCR ID#	FRCC	115	10472	2086
242	NCR ID#	FRCC	115	10243	2040
228	NCR ID#	FRCC	115	10089	2010
248	NCR ID#	FRCC	115	9865	1965
217	NCR ID#	FRCC	115	9560	1904
297	NCR ID#	FRCC	115	9521	1896
209	NCR ID#	FRCC	115	9295	1851
243	NCR ID#	FRCC	115	8969	1787
218	NCR ID#	FRCC	115	8926	1778
265	NCR ID#	FRCC	115	8913	1775
232	NCR ID#	FRCC	115	8882	1769
210	NCR ID#	FRCC	115	8875	1768
240	NCR ID#	FRCC	115	8538	1701
239	NCR ID#	FRCC	115	8442	1681
307	NCR ID#	FRCC	115	8397	1673
270	NCR ID#	FRCC	115	8349	1663
272	NCR ID#	FRCC	115	8193	1632
258	NCR ID#	FRCC	115	8000	1593
310	NCR ID#	FRCC	115	7891	1572
211	NCR ID#	FRCC	115	7837	1561
261	NCR ID#	FRCC	115	7822	1558
225	NCR ID#	FRCC	115	7730	1540
234	NCR ID#	FRCC	115	7557	1505
233	NCR ID#	FRCC	115	7543	1502

A. Introduction

1. **Title:** **Define Regional Disturbance Monitoring and Reporting Requirements**
2. **Number:** PRC-002-1
3. **Purpose:** Ensure that Regional Reliability Organizations establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of Disturbance data to facilitate analyses of events and verify system models.
4. **Applicability**

   4.1. Regional Reliability Organization.
5. **Effective Date:** Nine months after BOT adoption.

B. Requirements

R1. The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:

R1.1. Location, monitoring and recording requirements, including the following:

R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R1.1.2. Devices to be monitored.

R2. The Regional Reliability Organization shall establish the following installation requirements for fault recording:

R2.1. Location, monitoring and recording requirements, including the following:

R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).

R2.1.2. Elements to be monitored at each location.

R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R2.1.3.1. Three phase to neutral voltages.

R2.1.3.2. Three phase currents and neutral currents.

R2.1.3.3. Polarizing currents and voltages, if used.

R2.1.3.4. Frequency.

R2.1.3.5. Megawatts and megavars.

R2.2. Technical requirements, including the following:

R2.2.1. Recording duration requirements.

R2.2.2. Minimum sampling rate of 16 samples per cycle.

R2.2.3. Event triggering requirements.

R3. The Regional Reliability Organization shall establish the following installation requirements for dynamic Disturbance recording:

R3.1. Location, monitoring and recording requirements including the following:

R3.1.1. Criteria for equipment location giving consideration to the following:

- Site(s) in or near major load centers
- Site(s) in or near major generation clusters
- Site(s) in or near major voltage sensitive areas
- Site(s) on both sides of major transmission interfaces
- A major transmission junction
- Elements associated with Interconnection Reliability Operating Limits
- Major EHV interconnections between control areas
- Coordination with neighboring regions within the interconnection

R3.1.2. Elements and number of phases to be monitored at each location.

R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following:

R3.1.3.1. Voltage, current and frequency.

R3.1.3.2. Megawatts and megavars.

R3.2. Technical requirements, including the following:

R3.2.1. Capability for continuous recording for devices installed after January 1, 2009.

R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.

R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following:

R4.1. Criteria for events that require the collection of data from DMEs.

R4.2. List of entities that must be provided with recorded Disturbance data.

R4.3. Timetable for response to data request.

R4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE[1] analysis tool,

R4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files[2].

R4.6. Data content requirements and guidelines.

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[1] IEEE C37.111-1999 IEEE Standard Common Format for Transient Data Exchange for Power Systems or its successor standard

[2] Compliance with this requirement is not effective until the IEEE Standard is approved.

R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.

R6. The Regional Reliability Organization shall periodically (at least every five years) review, update and approve its Regional requirements for Disturbance monitoring and reporting.

C. Measures

M1. The Regional Reliability Organization's requirements for the installation of Disturbance Monitoring Equipment shall address Requirements 1 through 3.

M2. The Regional Reliability Organization's Disturbance monitoring data reporting requirements shall include all elements identified in Requirements 4.

M3. The Regional Reliability Organization shall have evidence it provided its Regional Disturbance monitoring and reporting requirements as required in Requirement 5.

M4. The Regional Reliability Organization shall have evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its DME requirements for three years.

The Compliance Monitor will retain its audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through providing its documentation of Disturbance Monitoring and Reporting requirements or self-certification as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exist:

2.1.1 Disturbance data reporting requirements were not specified as required in R4.1 through R4.6.

2.1.2 No evidence it conducted a review at least once every five years of its regional requirements for Disturbance monitoring and reporting as required in R6.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions exist:

2.2.1 Technical requirements were not specified for one or more types of DMEs.

2.2.2 Requirements do not provide criteria for equipment location or criteria for monitored elements or monitored quantities as required R1, R2 and R3.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Disturbance monitoring and reporting requirements were not available or were not provided to Transmission Owners and Generator Owners.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Disturbance Monitoring Equipment Installation and Data Reporting**

2. **Number:** PRC-018-1

3. **Purpose:** Ensure that Disturbance Monitoring Equipment (DME) is installed and that Disturbance data is reported in accordance with regional requirements to facilitate analyses of events.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

5. **Effective Dates:** Phased in over four years after BOT adoption:

   Requirements 1 and 2:

   – 50% compliant two years after initial issuance of regional requirements per RELIABILITY STANDARD PRC-002 Requirement 5.

   – 75% compliant three years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   – 100% compliant four years after initial issuance of regional requirements per reliability standard PRC-002 R5.

   Requirements 3 through 6:

   – 100% compliant six months after BOT adoption for already installed DME.

   – 100% compliant six months after installation for DMEs installed to meet Regional Reliability Organization requirements per reliability standard PRC-002 Requirements 1, 2 and 3.

B. Requirements

R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements:

R1.1. Internal Clocks in DME devices shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC)

R1.2. Recorded data from each Disturbance shall be retrievable for ten calendar days..

R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3).

R3. The Transmission Owner and Generator Owner shall each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1):

R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder).

R3.2. Make and model of equipment.

R3.3. Installation location.

R3.4. Operational status.

R3.5. Date last tested.

R3.6. Monitored elements, such as transmission circuit, bus section, etc.

R3.7. Monitored devices, such as circuit breaker, disconnect status, alarms, etc.

R3.8. Monitored electrical quantities, such as voltage, current, etc.

R4. The Transmission Owner and Generator Owner shall each provide Disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard PRC-002 Requirement 4).

R5. The Transmission Owner and Generator Owner shall each archive all data recorded by DMEs for Regional Reliability Organization-identified events for at least three years.

R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:

R6.1. Maintenance and testing intervals and their basis.

R6.2. Summary of maintenance and testing procedures.

C. Measures

M1. The Transmission Owner and Generator Owner shall each have evidence that DMEs it is required to have meet the functional requirements specified in Requirement 1 and are installed in accordance with its associated Regional Reliability Organization's requirements (R2).

M2. The Transmission Owner and Generator Owner shall each maintain the data listed in Requirements 3.1 through 3.8 for the DMEs installed to meet its Regional Reliability Organization's DME installation requirements.

M2.1 The Transmission Owner and Generator Owner shall each have evidence it provided this DME data to its Regional Reliability Organization within 30 calendar days of a request.

M3. The Transmission Owner and Generator Owner shall each have evidence it retained and provided recorded Disturbance data to entities in accordance with its associated Regional Reliability Organization's Disturbance data reporting requirements. (R4 R5)

M4. Each Transmission Owner and Generator Owner that is required to install DMEs to meet its Regional Reliability Organization's DME installation requirements, shall have an associated DME maintenance and testing program as defined in Requirement 6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each retain any Disturbance data provided to the Regional Reliability Organization (Requirement 4) for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions is present:

2.1.1 DMEs that meet all the Regional Reliability Organization's installation requirements (in accordance with Requirement 2) were installed at 90% or more but not all of the required locations.

2.1.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with Requirement 4) was provided for 90% or more but not all of the required locations.

2.1.3 Data on required DMEs was incomplete (in accordance with R3)

2.1.4 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 80% or more but less than 90% of the required locations.

2.2.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 80% or more but less than 90% of the required locations.

2.2.3 Recorded Disturbance data was not provided to all required entities (in accordance with R4)

2.2.4 Archived data was not retained for three years (in accordance with Requirement 5).

2.2.5 Documentation of the DME maintenance and testing program provided was complete as required in R6, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions is present:

2.3.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at 70% or more but less than 80% of the required locations.

2.3.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for 70% or more but less than 80% of the required locations.

2.3.3 Documentation of the DME maintenance and testing program provided was incomplete as required in R6, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. Level 4: There shall be a level four non-compliance if any one of the following conditions is present:

2.4.1 DMEs that meet all Regional Reliability Organization's installation requirements (in accordance with R2) were installed at less than 70% of the required locations.

2.4.2 Recorded Disturbance data that meets all Regional Reliability Organization's Disturbance data requirements (in accordance with R4) was provided for less than 70% of the required locations.

2.4.3 DMEs that meet all functional requirements (in accordance with R1) were not installed at all required locations.

2.4.4 Documentation of the DME maintenance and testing program was not provided, or no evidence that the testing program did occur within the identified intervals

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking

Consideration of Issues and Directives

Project 2007-11 Disturbance Monitoring
PRC-002-2 Disturbance Monitoring and Reporting Requirements

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"For the reasons stated in the NOPR, the Commission will not approve or remand PRC-002-1." "We agree with [American Public Power Association], Alcoa and Otter Tail that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards. Consistent with that goal, the Commission directs the ERO to consider APPA, Alcoa and Otter Tail's suggestions in the Reliability Standards development process as it modifies PRC-002-1 to provide missing information needed for the Commission to act on this Reliability Standard." (see below for American Public Power Association, Alcoa, and Otter Tail discussion)	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1455-56	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances. The use of recording and specifying recording data parameters, greater consistency is achieved in PRC-002-2.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in addressing the completion of this Reliability Standard."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1452	PRC-002-2 will apply on a continent-wide basis and will ensure that there is adequate data available to facilitate event analysis of Bulk Electric System (BES) Disturbances.
"Alcoa suggests that the ERO—instead of a Regional Entity—should define the requirements for DME and the type of report it generates. The requirements and equipment specifications should be consistent throughout North America. In addition, Alcoa suggests that the criteria for installation of such equipment should include the necessary monitoring and recording that contribute to analysis and enhance reliability."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 1453	Determines the key locations for which Disturbance data must be recorded which eliminates the need for equipment requirements. PRC-002-2 specifies the storage requirements and recording format for the collected data to ensure continent-wide uniformity to expedite event analysis.
"Otter Tail suggests that PRC-002-1 should be developed on an Interconnection wide basis to ensure consistency and promote reliability of the Bulk-Power System."	FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards	PRC-002-2 will apply on a continent-wide basis.

Project 2007-11- Disturbance Monitoring		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
	for the Bulk-Power System (Issued March 16, 2007); Paragraph 1454	
"The Commission requires supplemental information for any Reliability Standard that currently requires a regional reliability organization to fill in missing criteria or procedures. Where important information has not yet been provided to us to enable us to complete our review, we are not in a position to approve or remand those Reliability Standards. Accordingly, we will not approve or remand such Reliability Standards until the ERO submits further information. Until such information is provided, compliance with fill-in-the-blank standards should continue on a voluntary basis, and the Commission considers compliance with such Reliability Standards to be a matter of good utility practice."	Fill-in-the-blank Consideration FERC Docket No. RM06-16-000; Order No. 693; Mandatory Reliability Standards for the Bulk-Power System (Issued March 16, 2007); Paragraph 297.	By addressing recording instead of equipment, the Drafting Team has produced a continent-wide standard to have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.

Project 2007-11 – Disturbance Monitoring

PRC-002-2 – Disturbance Monitoring and Reporting Requirements

Mapping Document for PRC-018-1 to PRC-002-2 and PRC-002-1 to PRC-002-2

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that arise from the inherent differences between regional power systems. PRC-018-1 and PRC-002-1 deal with equipment, PRC-002-2 deals with recording. By specifying data instead of equipment, PRC-002-2 governs the practical capturing of abnormal event data on the BES.

PRC-018-1 Requirements reference PRC-002-1 which requires PRC-018-1 Requirements to be either retired or covered in PRC-002-2.

Standard PRC-018-1 (To be Retired) **FERC Approved**	**Proposed Standard PRC-002-2**
R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard **PRC-002 Requirements 1-3**) shall have DMEs installed that meet the following requirements:	**R10.** Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset. 10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1.1. Internal Clocks in DME devices shall be synchronized to **within 2 milliseconds** or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be **retrievable for ten calendar days**.	**R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded. **11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor. **11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2. **11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later. **11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.
Notes: PRC-018-1, Requirement R1 is covered in PRC-002-2, Requirements R10 and R11.	

<table>
<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td colspan="2">PRC-018-1 addresses the equipment used for Disturbance monitoring data recording, PRC-002-2 addresses the recorded data. Technological advances made in the types of equipment used to record power system data have made it more effective to direct PRC-002-2 at the recording, not the equipment. Time synchronization and having the data retrievable for 10 days are general parameters that facilitate data analysis. PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirement R11.</td></tr>
<tr><td>R2. The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization’s installation requirements (reliability standard PRC-002 Requirements 1 through 3).

PRC-002-1
R1. The Regional Reliability Organization shall establish the following installation requirements for sequence of event recording:
R1.1. Location, monitoring and recording requirements, including the following:

R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.).
R1.1.2. Devices to be monitored</td><td>R1. Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.
1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.
1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns</td></tr>
</table>

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1.Location, monitoring and recording requirements, including the following: R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars. R2.2.Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements. R3. The Regional Reliability Organization shall establish the following installation	connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **3.1** Phase-to-neutral voltage for each phase of each specified BES bus. **3.2** Each phase current and the residual or neutral current for the following BES Elements: **3.2.1** Transformers that have a low-side operating voltage of 100kV or above. **3.2.2** Transmission Lines. **R4.** Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder. **4.2** A minimum recording rate of 16 samples per cycle. **4.3** Trigger settings for at least the following: **4.3.1** Neutral (residual) overcurrent. **4.3.2** Phase undervoltage or overcurrent.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
requirements for **dynamic Disturbance recording**: R3.1. Location, monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following:	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	**5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the reevaluated list of BES Elements as per the Implementation Plan. R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **6.1** One phase-to-neutral or positive sequence voltage. **6.2** The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. **6.3** Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. **6.4** Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for wich it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

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<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td></td><td>
7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up (GSU) transformer high-side or low-side voltage level.
7.2. The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.
7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.
7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1.
R8. Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
8.1. Triggered record lengths of at least three minutes.
8.2. At least one of the following three triggers:
Off nominal frequency trigger set at:
<table>
<tr><th></th><th>Low</th><th>High</th></tr>
<tr><td>o Eastern Interconnection</td><td><59.75 Hz</td><td>>61.0 Hz</td></tr>
<tr><td>o Western Interconnection</td><td><59.55 Hz</td><td>>61.0 Hz</td></tr>
<tr><td>o ERCOT Interconnection</td><td><59.35 Hz</td><td>>61.0 Hz</td></tr>
<tr><td>o Hydro-Quebec Interconnection</td><td><58.55 Hz</td><td>>61.5 Hz</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td></td><td>

- Rate of change of frequency trigger set at:
  - Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec
  - Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec
  - ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec
  - Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meets the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.
</td></tr>
<tr><td colspan="2">Notes: PRC-018-1, Requirement R2 and PRC-002-1 Requirements R1-R3 are covered in PRC-002-2, Requirements R1-R9. PRC-018-1, Requirement R2 references PRC-002-1 Requirements R1-R2. PRC-002-1, Requirements R1-R3 reference equipment installation requirements for FR, SER, and DDR. The technical parameters of PRC-002-2 pertain to the characteristics and content of the recordings that are needed to facilitate event analysis.</td></tr>
<tr><td>R3. The Transmission Owner and Generator Owner shall</td><td>None.</td></tr>
</table>

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker,	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
disconnect status, alarms, etc. R3.8.Monitored electrical quantities, such as voltage, current, etc.	
Notes: PRC-018-1, Requirement R3 is not covered in PRC-002-2. PRC-018-1 Requirement R3 refers to equipment and therefore is not mapped to PRC-002-2 which deals with recorded data and not equipment.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R4. The Transmission Owner and Generator Owner shall each **provide Disturbance data** (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard **PRC-002 Requirement 4**). **PRC-002-1** R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool.	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
Notes: PRC-018-1, Requirement R4 references PRC-002-1 Requirement R4 which is covered is PRC-002-2, Requirement R11.	
R5. The Transmission Owner and Generator Owner shall each **archive all data** recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	Covered in the Compliance section **1.2 Evidence Retention** The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation: The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years. The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years. The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years. The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years. If a Transmission Owner, Generator Owner, or Responsible Entity (Planning Coordinator or Reliability Coordinator) is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.
Notes: PRC-018-1, Requirement R5 is covered in the PRC-002-2 Compliance section under Evidence Retention.	
R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	**R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the SER, FR or DDR data either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R6.1. Maintenance and testing intervals and their basis. R6.2. Summary of maintenance and testing procedures.	
Notes: PRC-018-1, Requirement R6 is covered in PRC-002-2, Requirement R12. PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R12 deals with the long term availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability.	

Standard PRC-002-1	Proposed Standard PRC-002-2
R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event recording**: R1.1. Location, monitoring and recording requirements, including the following:	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data;

Standard PRC-002-1	Proposed Standard PRC-002-2
R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored	1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified per Requirement R1 and associated with the BES Elements at those BES buses. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
Notes: PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirements R1-R2. (See PRC-018-1, Requirement R3 above for additional information.)	
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1. Location , monitoring and recording requirements, including the following:	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1;

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars.	1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements they own connected to the BES buses identified per Requirement R1: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 3.1 Phase-to-neutral voltage for each phase of each specified line or BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1. Transformers that have a low-side operating voltage of 100kV or above. 3.2.2. Transmission Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include:

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.2. Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements.	• A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault as seen by the fault recorder. **4.2.** A minimum recording rate of 16 samples per cycle. **4.3.** Trigger settings for at least the following: **4.3.1.** Neutral (residual) overcurrent. **4.3.2.** Phase undervoltage or overcurrent.
Notes: PRC-002-1, Requirement R2 is covered in PRC-002-2, Requirements R1, R2, R4, and R5.	
R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**: R3.1. Location , monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

Standard PRC-002-1	Proposed Standard PRC-002-2
consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored	**5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element **5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the reevaluated list of BES Elements as per the Implementation Plan. **R6.** Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notifications as identified in

Standard PRC-002-1	Proposed Standard PRC-002-2
element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. **R8.** Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified as per Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz

Standard PRC-002-1	Proposed Standard PRC-002-2
	o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meets the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-002-1, Requirement R3 is covered in PRC-002-2, Requirements R5-R6 and R8-R9.	
R4. The Regional Reliability Organization shall establish requirements for facility owners	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per

Standard PRC-002-1	Proposed Standard PRC-002-2
to **report Disturbance data recorded** by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool, 4.5. Naming of data files in conformance with the IEEE	Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

Standard PRC-002-1	Proposed Standard PRC-002-2
C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	
Notes: PRC-002-1, Requirement R4 is covered in PRC-002-2, Requirement R13.	
R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the reevaluated list of BES Elements as per the Implementation Plan.
Notes: PRC-002-1, Requirement R5 is covered in PRC-002-2, Requirements R2, R6-R7.	
R6. The Regional Reliability Organization shall periodically (**at least every five years**) review, update and approve its Regional requirements for Disturbance monitoring and reporting.	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the reevaluated list of BES Elements as per the Implementation Plan.
Notes: PRC-002-1, Requirement R6 is covered in PRC-002-2, Requirements R1 and R5.	

Project 2007-11 – Disturbance Monitoring

PRC-002-2 – Disturbance Monitoring and Reporting Requirements

Mapping Document for PRC-018-1 to PRC-002-2 and PRC-002-1 to PRC-002-2

PRC-002-2 addresses the recording (data), not "how" the data is recorded, thus eliminating the complications that arise from the inherent differences between regional power systems. PRC-018-1 and PRC-002-1 deal with equipment, PRC-002-2 deals with recording. By specifying data instead of equipment, PRC-002-2 governs the practical capturing of abnormal event data on the BES.

PRC-018-1 Requirements reference PRC-002-1 which requires PRC-018-1 Requirements to be either retired or covered in PRC-002-2.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1. Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard **PRC-002 Requirements 1-3**) shall have DMEs installed that meet the following requirements:	**R10.** Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to~~hat~~ meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset. 10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R1.1. Internal Clocks in DME devices shall be synchronized to **within 2 milliseconds** or less of Universal Coordinated Time scale (UTC) R1.2. Recorded data from each Disturbance shall be **retrievable for ten calendar days**.	**R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded. **11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor. **11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2. **11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later. **11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.
Notes: PRC-018-1, Requirement R1 is covered in PRC-002-2, Requirements R10 and R11.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
PRC-018-1 addresses the equipment used for Disturbance monitoring data recording, PRC-002-2 addresses the recorded data. Technological advances made in the types of equipment used to record power system data have made it more effective to direct PRC-002-2 at the recording, not the equipment. Time synchronization and having the data retrievable for 10 days are general parameters that facilitate data analysis. PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirement R11.	
R2. The Transmission Owner and Generator Owner shall each **install DMEs in accordance with** its Regional Reliability Organization's installation requirements (reliability standard **PRC-002 Requirements 1 through 3**). **PRC-002-1** R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event recording**: R1.1. Location, monitoring and recording requirements, including the following: R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored	**R1.** Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1. 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data. 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan. **R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1.Location, monitoring and recording requirements, including the following: R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars. R2.2.Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements. R3. The Regional Reliability Organization shall establish the following installation	connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **3.1** Phase-to-neutral voltage for each phase of each specified BES bus. **3.2** Each phase current and the residual or neutral current for the following BES Elements: **3.2.1** Transformers that have a low-side operating voltage of 100kV or above. **3.2.2** Transmission Lines. **R4.** Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include: • A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point, or • At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder. **4.2** A minimum recording rate of 16 samples per cycle. **4.3** Trigger settings for at least the following: **4.3.1** Neutral (residual) overcurrent. **4.3.2** Phase undervoltage or overcurrent.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
requirements for **dynamic Disturbance recording**: R3.1. Location, monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following:	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** ~~Ensure~~Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	**5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3~~, and~~ to implement the reevaluated list of BES Elements as per the Implementation Plan. R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **6.1** One phase-to-neutral or positive sequence voltage. **6.2** The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. **6.3** Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required. **6.4** Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for wich it received notification as identified in Requirement R5: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	7.1. One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up (GSU) transformer high-side or low-side voltage level. 7.2. The phase current for the same phase at the same voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current. 7.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 7.4. Frequency of at least one of the voltages in Requirement R7, Part 7.1. R8. Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	• Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meets the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-018-1, Requirement R2 and PRC-002-1 Requirements R1-R3 are covered in PRC-002-2, Requirements R1-R9. PRC-018-1, Requirement R2 references PRC-002-1 Requirements R1-R2. PRC-002-1, Requirements R1-R3 reference equipment installation requirements for FR, SER, and DDR. The technical parameters of PRC-002-2 pertain to the characteristics and content of the recordings that are needed to facilitate event analysis.	
R3. The Transmission Owner and Generator Owner shall	None.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
each maintain, and report to its Regional Reliability Organization on request, the following data on the DMEs installed to meet that region's installation requirements (reliability standard PRC-002 Requirements1.1, 2.1 and 3.1): R3.1. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder). R3.2. Make and model of equipment. R3.3. Installation location. R3.4. Operational status. R3.5. Date last tested. R3.6. Monitored elements, such as transmission circuit, bus section, etc. R3.7. Monitored devices, such as circuit breaker,	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
disconnect status, alarms, etc. R3.8.Monitored electrical quantities, such as voltage, current, etc.	
Notes: PRC-018-1, Requirement R3 is not covered in PRC-002-2. PRC-018-1 Requirement R3 refers to equipment and therefore is not mapped to PRC-002-2 which deals with recorded data and not equipment.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
R4. The Transmission Owner and Generator Owner shall each **provide Disturbance data** (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements (reliability standard **PRC-002 Requirement 4**). **PRC-002-1** R4. The Regional Reliability Organization shall establish requirements for facility owners to report Disturbance data recorded by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool.	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
4.5. Naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
Notes: PRC-018-1, Requirement R4 references PRC-002-1 Requirement R4 which is covered is PRC-002-2, Requirement R11.	
R5. The Transmission Owner and Generator Owner shall each **archive all data** recorded by DMEs for Regional Reliability Organization-identified events for at least three years.	Covered in the Compliance section **1.2 Evidence Retention** The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation: The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years. The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years. The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

Standard PRC-018-1 (To be Retired) FERC Approved	Proposed Standard PRC-002-2
	The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years. The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years. If a Transmission Owner, Generator Owner, or Responsible Entity (Planning Coordinator or Reliability Coordinator) is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.
Notes: PRC-018-1, Requirement R5 is covered in the PRC-002-2 Compliance section under Evidence Retention.	
R6. Each Transmission Owner and Generator Owner that is required by its Regional Reliability Organization to have DMEs shall have a maintenance and testing program for those DMEs that includes:	**R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the SER, FR or DDR data either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* • Restore the recording capability, or • Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

<table>
<tr><th>Standard PRC-018-1 (To be Retired)
FERC Approved</th><th>Proposed Standard PRC-002-2</th></tr>
<tr><td>R6.1. Maintenance and testing intervals and their basis.

R6.2. Summary of maintenance and testing procedures.</td><td></td></tr>
<tr><td colspan="2">Notes: PRC-018-1, Requirement R6 is covered in PRC-002-2, Requirement R12.

PRC-018-1, Requirement R6 deals with routine maintenance and testing of equipment. PRC-002-2, Requirement R12 deals with the long term availability of recording capability. Both Requirements are meant to ensure the availability of the recording of data. By requiring the TOs and GOs to notify their Regional Entity reinforces the importance of the available recording capability.</td></tr>
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Standard PRC-002-1	Proposed Standard PRC-002-2
R1. The Regional Reliability Organization shall establish the following installation requirements for **sequence of event recording**: R1.1. Location, monitoring and recording requirements, including the following:	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data;

Standard PRC-002-1	Proposed Standard PRC-002-2
R1.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R1.1.2. Devices to be monitored	1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified per Requirement R1 and associated with the BES Elements at those BES buses. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
Notes: PRC-002-1, Requirement R1 is covered in PRC-002-2, Requirements R1-R2. (See PRC-018-1, Requirement R3 above for additional information.)	
R2. The Regional Reliability Organization shall establish the following installation requirements for **fault recording**: R2.1. Location , monitoring and recording requirements, including the following:	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1;

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.1.1. Criteria for equipment location (e.g., by voltage, geographic area, station size, etc.). R2.1.2. Elements to be monitored at each location. R2.1.3. Electrical quantities to be recorded for each monitored element shall be sufficient to determine the following: R2.1.3.1. Three phase to neutral voltages. R2.1.3.2. Three phase currents and neutral currents. R2.1.3.3. Polarizing currents and voltages, if used. R2.1.3.4. Frequency. R2.1.3.5. Megawatts and megavars.	1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan. **R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements they own connected to the BES buses identified per Requirement R1: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 3.1 Phase-to-neutral voltage for each phase of each specified line or BES bus. 3.2 Each phase current and the residual or neutral current for the following BES Elements: 3.2.1. Transformers that have a low-side operating voltage of 100kV or above. 3.2.2. Transmission Lines. R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **4.1** A single record or multiple records that include:

Standard PRC-002-1	Proposed Standard PRC-002-2
R2.2. Technical requirements, including the following: R2.2.1.Recording duration requirements. R2.2.2. Minimum sampling rate of 16 samples per cycle. R2.2.3. Event triggering requirements.	• A pre-trigger record length of at least two cycles and a total record length of at least 30 cycles for the same trigger point. • At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault as seen by the fault recorder. **4.2.** A minimum recording rate of 16 samples per cycle. **4.3.** Trigger settings for at least the following: **4.3.1.** Neutral (residual) overcurrent. **4.3.2.** Phase undervoltage or overcurrent.
Notes: PRC-002-1, Requirement R2 is covered in PRC-002-2, Requirements R1, R2, R4, and R5.	
R3. The Regional Reliability Organization shall establish the following installation requirements for **dynamic Disturbance recording**: R3.1. Location , monitoring and recording requirements including the following: R3.1.1.Criteria for equipment location giving	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

Standard PRC-002-1	Proposed Standard PRC-002-2
consideration to the following: -Site(s) in or near major load centers -Site(s) in or near major generation clusters -Site(s) in or near major voltage sensitive areas -Site(s) on both sides of major transmission interfaces -A major transmission junction -Elements associated with Interconnection Reliability Operating Limits -Major EHV interconnections between control areas -Coordination with neighboring regions within the interconnection R3.1.2. Elements and number of phases to be monitored at each location. R3.1.3. Electrical quantities to be recorded for each monitored	**5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element **5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to~~, and~~ implement the reevaluated list of BES Elements as per the Implementation Plan. **R6.** Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notifications as identified in

Standard PRC-002-1	Proposed Standard PRC-002-2
element shall be sufficient to determine the following: R3.1.3.1. Voltage, current and frequency. R3.1.3.2. Megawatts and megavars. R3.2. Technical requirements, including the following: R3.2.1. Capability for continuous recording for devices installed after January 1, 2009. R3.2.2. Each device shall sample data at a rate of at least 960 samples per second and shall record the RMS value of electrical quantities at a rate of at least 6 records per second.	Requirement R5, to determine the following electrical quantities: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 6.1 One phase-to-neutral or positive sequence voltage. 6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current. 6.3 Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required. 6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1. **R8.** Each Transmission Owner and Generator Owner that is responsible for DDR data for the BES Elements identified as per Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 8.1. Triggered record lengths of at least three minutes. **8.2.** At least one of the following three triggers: • Off nominal frequency trigger set at: Low / High o Eastern Interconnection <59.75 Hz >61.0 Hz o Western Interconnection <59.55 Hz >61.0 Hz o ERCOT Interconnection <59.35 Hz >61.0 Hz

Standard PRC-002-1	Proposed Standard PRC-002-2
	o Hydro-Quebec Interconnection <58.55 Hz >61.5 Hz • Rate of change of frequency trigger set at: o Eastern Interconnection < -0.03125 Hz/sec > 0.125 Hz/sec o Western Interconnection < -0.05625 Hz/sec > 0.125 Hz/sec o ERCOT Interconnection < -0.08125 Hz/sec > 0.125 Hz/sec o Hydro-Quebec Interconnection < -0.18125 Hz/sec > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85% of normal operating voltage for a duration of 5 seconds R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meets the following technical specifications: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* 9.1 Input sampling rate of at least 960 samples per second. 9.2 Output recording rate of electrical quantities of at least 30 times per second.
Notes: PRC-002-1, Requirement R3 is covered in PRC-002-2, Requirements R5-R6 and R8-R9.	
R4. The Regional Reliability Organization shall establish requirements for facility owners	**R11.** Each Transmission Owner and Generator Owner shall provide SER, FR, and DDR data for the BES bus locations identified per Requirement R1 and BES Elements identified per

Standard PRC-002-1	Proposed Standard PRC-002-2
to **report Disturbance data recorded** by their DME installations. The Disturbance data reporting requirements shall include the following: 4.1. Criteria for events that require the collection of data from DMEs. 4.2. List of entities that must be provided with recorded Disturbance data. 4.3. Timetable for response to data request. 4.4. Provision for reporting Disturbance data in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool, 4.5. Naming of data files in conformance with the IEEE	Requirement R5 to the Reliability Coordinator, Regional Entity, or NERC: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **11.1.** The recorded data will be provided within 30 calendar days of a request. **11.2.** The recorded data will be retrievable for the period of 10 calendar days preceding a request. **11.3.** SER data will be provided in ASCII Comma Separated Value (.CSV) format following Attachment 2. **11.4.** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111.1999 or later. **11.5.** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

Standard PRC-002-1	Proposed Standard PRC-002-2
C37.232 Recommended Practice for Naming Time Sequence Data Files. 4.6. Data content requirements and guidelines.	
Notes: PRC-002-1, Requirement R4 is covered in PRC-002-2, Requirement R13.	
R5. The Regional Reliability Organization shall provide its requirements (and any revisions to those requirements) including those for DME installation and Disturbance data reporting to the affected Transmission Owners and Generator Owners within 30 calendar days of approval of those requirements.	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to~~, and~~ implement the reevaluated list of BES Elements as per the Implementation Plan.
Notes: PRC-002-1, Requirement R5 is covered in PRC-002-2, Requirements R2, R6-R7.	
R6. The Regional Reliability Organization shall periodically (**at least every five years**) review, update and approve its Regional requirements for Disturbance monitoring and reporting.	**R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1; 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1 that those BES Elements require SER data and/or FR data; 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the reevaluated list of BES buses as per the Implementation Plan.

Standard PRC-002-1	Proposed Standard PRC-002-2
	R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]* **5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.1** Generating resource(s) with: **5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA. **5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. **5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL). **5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter. **5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROL). **5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program. **5.2** Ensure a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: **5.2.1** One BES Element

Standard PRC-002-1	Proposed Standard PRC-002-2
	5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. **5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. **5.4** Reevaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to~~, and~~ implement the reevaluated list of BES Elements as per the Implementation Plan.
Notes: PRC-002-1, Requirement R6 is covered in PRC-002-2, Requirements R1 and R5.	

Project 2007-11 Disturbance Monitoring

VRF and VSL Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PRC-002-2 – Disturbance Monitoring and Reporting Requirements.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined by the ERO Sanctions Guidelines.

The Disturbance Monitoring and Reporting Requirements Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria –VRFs

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC VRF Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed VRF	**Lower**
NERC VRF Discussion	R1 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R1 establishes the list of Sequence of Events Recordings and Fault Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for establishing a list of BES bus locations for Sequence of Events Recording and Fault Recording using the selection procedure in Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish the list of BES bus locations for Sequence of Events Recording and Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective which is to establish a list of BES bus locations for Sequence of Events Recording and Fault Recording and to review the list every 5-calendar years. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Lower VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80% but less than 100% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by 10-calendar days or less.
Proposed Moderate VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70% but less than or equal to 80% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.
Proposed High VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60% but less than or equal to 70% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.

VRF and VSL Justifications – PRC-002-2, R1	
Proposed Severe VSL	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60% of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by greater than 30-calendar days.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: The VSL assignment is for R1 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R1	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R2	
Proposed VRF	**Lower**
NERC VRF Discussion	R2 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R2 provides criteria for Sequence of Events Recording which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Sequence of Events Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Sequence of Events Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective which is to establish criteria for Sequence of Events Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 80% but less than 100% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Moderate VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 70% but less than or equal to 80% of the total SER

VRF and VSL Justifications – PRC-002-2, R2	
	data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed High VSL	Each Transmission or Generator Owner as directed by Requirement R2 had more than 60% but less than or equal to 70% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
Proposed Severe VSL	Each Transmission or Generator Owner as directed by Requirement R2 for less than or equal to 50% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the bus locations as per Requirement R2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R2 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R3	
Proposed VRF	**Lower**
NERC VRF Discussion	R3 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R3 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recording selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R3 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80% but less than 100% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70% but less than or equal to 80% of the total set of required electrical quantities, which is the product of the total number of monitored BES

VRF and VSL Justifications – PRC-002-2, R3	
	Elements and the number of specified electrical quantities per each Element.
Proposed High VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60% but less than or equal to 57% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60% of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities per each Element.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R4 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R4	
Proposed VRF	**Lower**
NERC VRF Discussion	R4 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R4 provides criteria for Fault Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Fault Recordings selected in R1, Attachment 1. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Fault Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R4 contains only one objective which is to establish criteria for Fault Recording. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had FR data that meets more than 80% but less than 100% of the total recording properties as specified in Requirement R4.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had FR data that meets more than 70% but less than or equal to 80% of the total recording properties as specified in Requirement R4.

VRF and VSL Justifications – PRC-002-2, R4	
Proposed High VSL	The Transmission Owner or Generator Owner had FR data that meets more than 60% but less than or equal to 70% of the total recording properties as specified in Requirement R4.
Proposed Severe VSL	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60% of the total recording properties as specified in Requirement R4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-002-2, R4	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R5	
Proposed VRF	**Lower**
NERC VRF Discussion	R5 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R5 establishes the list of Dynamic Disturbance Recordings that is consistent with FERC guideline G1, Recommendation 12 of the Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for identifying BES Elements for Dynamic Disturbance Recording. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to identify BES Elements for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R5 contains only one objective which identifies BES Elements within specified criteria and to review the list every 5-calendar years. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Responsible Entity identified the Elements for which DDR data is required as directed by Requirement R5 for more than 80% but less than 100% of the required Elements included in Part 5.1. OR

VRF and VSL Justifications – PRC-002-2, R5	
	The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.
Proposed Moderate VSL	The Responsible Entity identified the Elements for which DDR is required as directed by Requirement R5 for more than 70% but less than or equal to 80% of the required Elements included in Part 5.1. OR The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.
Proposed High VSL	The Responsible Entity identified the Elements for which DDR data is requires as directed by Requirement R5 for more than 60% but less than or equal to 70% of the required Elements included in Part 5.1. OR The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.
Proposed Severe VSL	The Responsible Entity identified the Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60% of the required Elements included in Part 5.1. OR

VRF and VSL Justifications – PRC-002-2, R5	
	The Responsible Entity identified the Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R5 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R5	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R6	
Proposed VRF	**Lower**
NERC VRF Discussion	R6 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R6 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R6 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R6	
Proposed Lower VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 75% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 50% but less than or equal to 75% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 0% but less than or equal to 50% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R6	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R7	
Proposed VRF	**Lower**
NERC VRF Discussion	R7 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R7 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes criteria for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish criteria for Dynamic Disturbance Recording could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R7 contains only one objective which is to establish criteria for Dynamic Disturbance Recording. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R7	
Proposed Lower VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80% but less than 100% of the total required electrical quantities for all applicable BES Elements.
Proposed Moderate VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70% but less than or equal to 80% of the total required electrical quantities for all applicable BES Elements.
Proposed High VSL	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60% but less than or equal to 70% of the total required electrical quantities for all applicable BES Elements.
Proposed Severe VSL	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments	Guideline 2a: The VSL assignment is for R7 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R7	
that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the ‘weakest link’ characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R8	
Proposed VRF	**Lower**
NERC VRF Discussion	R8 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R8 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement establishes the need for continuous data recording and storage for Dynamic Disturbance Recordings established in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R8 contains only one objective to establish continuous data recording and storage for Dynamic Disturbance Recordings established in R6. Since the requirement has only one objective, only one VRF was assigned.

VRF and VSL Justifications – PRC-002-2, R8	
Proposed Lower VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80% but less than 100% of the Elements they own as determined in Requirement R5.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70% but less than or equal to 80% of the Elements they own as determined in Requirement R5.
Proposed High VSL	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 6% but less than or equal to 70% of the Elements they own as determined in Requirement R5.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the Elements they own as determined in Requirement R5.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R8 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R8	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R9	
Proposed VRF	**Lower**
NERC VRF Discussion	R9 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R9 provides criteria for Dynamic Disturbance Recordings which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement established technical specifications for Dynamic Disturbance Recording selected in R6. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to establish technical specifications for Dynamic Disturbance Recording selected in R6 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R9 contains only one objective which is to establish technical specifications for Dynamic Disturbance Recording selected in R6. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 80% but less than 100% of the total recording properties as specified in Requirement R9.

VRF and VSL Justifications – PRC-002-2, R9	
Proposed Moderate VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 70% but less than or equal to 80% of the total recording properties as specified in Requirement R9.
Proposed High VSL	The Transmission Owner or Generator Owner had DDR data that meets more than 60% but less than or equal to 70% of the total recording properties as specified in Requirement R9.
Proposed Severe VSL	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60% of the total recording properties as specified in Requirement R9.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is for R9 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	**Guideline 3- Consistency among Reliability Standards**

VRF and VSL Justifications – PRC-002-2, R9	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This requirement established technical specifications for Dynamic Disturbance Recording selected in R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R10	
Proposed VRF	**Lower**
NERC VRF Discussion	R10 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R10 requires time synchronization of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data which falls under Recommendation 12 of the Blackout Report and is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement calls for time synchronization for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations established in R1 and R5. The team could not identify other continent-wide reliability standards of the same nature.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failures to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R10 contains only one objective which is to time synchronize Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90% but less than 100% of the bus

VRF and VSL Justifications – PRC-002-2, R10	
	locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Moderate VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80% but less than or equal to 90% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed High VSL	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70% but less than or equal to 80% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
Proposed Severe VSL	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70% of the bus locations as per Requirements R1 and Elements as per Requirement R5 as directed by Requirement R10.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R10 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R10	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R11	
Proposed VRF	**Lower**
NERC VRF Discussion	R11 is administrative in nature and a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R11 provides criteria around timelines for providing the data and the data format. This is consistent with FERC guideline G1.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has parts that are of equal importance; only one VRF was assigned so there is no conflict.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria on providing Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data for locations selected in R1 and Elements established in R5 could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is "Lower" which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R11 contains only one objective which is to provide Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data within the specified criteria. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-

VRF and VSL Justifications – PRC-002-2, R11	
	calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90% but less than 100% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90% but less than 100% in the proper data format.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80% but less than or equal to 90% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80% but less than or equal to 90% in the proper data format.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70% but less than or equal to 80% of the requested data. OR

VRF and VSL Justifications – PRC-002-2, R11	
	The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70% but less than or equal to 80% in the proper data format.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70% of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70% in the proper data format.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL's provide a broader compliance range than the associated VSL's in PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is for R11 is not binary. Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF and VSL Justifications – PRC-002-2, R11	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	Non CIP

VRF and VSL Justifications – PRC-002-2, R12	
Proposed VRF	**Lower**
NERC VRF Discussion	R12 is a requirement in a long-term planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state of capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** R12 provides criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** This requirement does not have parts.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This requirement sets the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** Failure to follow the criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data could not directly affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES. Violation of the requirement will not lead to bulk electric system instability, separation, or cascading failures. The VRF for this requirement is “Lower” which is consistent with NERC guidelines for similar requirements.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R12 contains only one objective which is to establish criteria around the availability of Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data. Since the requirement has only one objective, only one VRF was assigned.
Proposed Lower VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action

VRF and VSL Justifications – PRC-002-2, R12	
	Plan to the Regional Entity more than 90-calendar days but less than 100-calendar days after discovery of the failure.
Proposed Moderate VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.
Proposed High VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.
Proposed Severe VSL	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-2 differs from PRC-002-1 (not enforceable) and PRC-018-1 (enforceable and will be retired upon approval of PRC-002-2) in that PRC-002-2 deals with Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording in order to adequately capture data for events analysis; and not equipment as referenced in the PRC-002-1 and PRC-018-1. Therefore, the VSL's cannot be compared between PRC-002-2 and PRC-018-1. The VSL's for this requirement meet or exceed the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure	Guideline 2a: The VSL assignment is for R12 is not binary.

VRF and VSL Justifications – PRC-002-2, R12	
Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: The propose VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	Non CIP
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and	Non CIP

VRF and VSL Justifications – PRC-002-2, R12	
implementation should account for their interdependence	

Standards Announcement

Project 2007-11 Disturbance Monitoring - PRC-002-2

Final Ballot Now Open through November 6, 2014

Now Available

A final ballot for **PRC-002-2 - Disturbance Monitoring and Reporting Requirements** is open through **8 p.m. Eastern, Thursday, November 6, 2014.**

Background information for this project can be found on the project page.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

The voting results for the standard will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Stephen Crutchfield, Standards Developer, or at 609-651-9455.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2007-11 Disturbance Monitoring

Final Ballot Results

Now Available

A final ballot for **PRC-002-2 - Disturbance Monitoring and Reporting Requirements** concluded at **8 p.m. Eastern, Thursday, November 6, 2014**.

The standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

PRC-002-2
Quorum/Approval
81.89% / 68.51%

Background information for this project can be found on the project page.

Next Steps

The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Standards Developer, Stephen Crutchfield (via email), or by telephone at 609-651-9455.

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Ballot Results	
Ballot Name:	Project 2007-11 DM PRC-002-2
Ballot Period:	10/28/2014 - 11/6/2014
Ballot Type:	Final
Total # Votes:	312
Total Ballot Pool:	381
Quorum:	**81.89 % The Quorum has been reached**
Weighted Segment Vote:	68.51 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	101	1	51	0.68	24	0.32	0	6	20
2 - Segment 2	8	0.6	6	0.6	0	0	0	1	1
3 - Segment 3	85	1	39	0.629	23	0.371	0	7	16
4 - Segment 4	29	1	10	0.556	8	0.444	0	7	4
5 - Segment 5	87	1	34	0.557	27	0.443	0	11	15
6 - Segment 6	51	1	23	0.605	15	0.395	0	6	7
7 - Segment 7	4	0.1	0	0	1	0.1	0	0	3
8 - Segment 8	5	0.3	2	0.2	1	0.1	0	0	2
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	8	0.7	7	0.7	0	0	0	1	0
Totals	**381**	**6.9**	**174**	**4.727**	**99**	**2.173**	**0**	**39**	**69**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Negative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Hudson Gas & Electric Corp.	Frank Pace		
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	COMMENT RECEIVED
1	City of Tallahassee	Daniel S Langston	Negative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Negative	COMMENT RECEIVED
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Negative	COMMENT RECEIVED
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Great River Energy	Gordon Pietsch	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John Chin		
1	Long Island Power Authority	Robert Ganley	Affirmative	

1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnesota Power, Inc.	Randi K. Nyholm	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Montana Dakota Utilities Co.	Teresa Hendrickson		
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Sam Rayburn G&T Inc.	William M Bateman		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	South Texas Electric Cooperative	Renee Davidson		
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	COMMENT RECEIVED
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		

1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Amy J Miller	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	
3	City of Homestead	Orestes J Garcia	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Negative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	El Paso Electric Company	Rhonda Bryant		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Guadalupe Valley Electric Cooperative	Robert B Christmas		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD

				PARTY COMMENTS
3	Lee County Electric Cooperative	David A Hadzima		
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Negative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe		
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell		
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante		

4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	AES Corporation	Leo Bernier		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Calpine Corporation	Hamid Zakery	Negative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	DTE Energy	Mark Stefaniak	Negative	COMMENT RECEIVED
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker		
5	EDP Renewables North America LLC	Mary L Ideus		
5	El Paso Electric Company	Gustavo Estrada		
5	Exelon Nuclear	Mark F Draper	Negative	
5	First Wind	John Robertson	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	
5	Invenergy LLC	Alan Beckham	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY

				COMMENTS
5	Liberty Electric Power LLC	Daniel Duff	Negative	COMMENT RECEIVED
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Abstain	
5	NaturEner USA, LLC	Andrew S Ace		
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Ontario Power Generation Inc.	David Ramkalawan		
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Abstain	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Negative	
				COMMENT

5	Xcel Energy, Inc.	Liam Noailles	Negative	RECEIVED
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	
6	Great River Energy	Donna Stephenson		
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Muscatine Power & Water	John Stolley	Abstain	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Abstain	
6	Powerex Corp.	Gordon Dobson-Mack	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Negative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Tampa Electric Co.	Benjamin F Smith II	Abstain	
6	Tennessee Valley Authority	Marjorie S Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	COMMENT RECEIVED
7	Alcoa, Inc.	Thomas Gianneschi		
7	Occidental Chemical	Venona Greaff	Negative	
7	Praxair Inc.	David Meade		
7	Valero Services, Inc.	Lee W Morris		

8		Roger C Zaklukiewicz	Negative	
8		Debra R Warner		
8		David L Kiguel	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	Gainesville Regional Utilities	Norman Harryhill		
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	

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Account Log-In/Register

Exhibit H

Standard Drafting Team Roster

Standard Drafting Team Roster

Project 2007-11 Disturbance Monitoring

Name and Title	Company and Address	Contact Info	Bio
Lee Pedowicz	Northeast Power Coordinating Council, Inc. 1040 Avenue of the Americas 10th Floor New York, New York 10018-3703	212-840-1070 ext 7061 lpedowicz@npcc.org	Lee Pedowicz is the Chair of the Drafting Team for Project 2007-11, Disturbance Monitoring, and the Manager, Reliability Standards for NPCC. Lee began his career with NPCC in November, 2007. He is responsible for submitting comments to relevant NERC and industry postings on behalf of NPCC, and coordinating NPCC's Regional Standards Committee meetings. Prior to joining NPCC, Lee was a Senior System Operator for Consolidated Edison in New York City responsible for the real-time on watch operation of the Con Edison electric and steam systems. The position was responsible for maintaining reliable real-time operating conditions, responding to system emergencies, and scheduling equipment outages. Lee was also a Manager in the Protective Systems Testing Department responsible for all aspects of protective relaying maintenance and testing, and the testing of transmission and distribution system equipment. Lee also worked for the Long Island Lighting Company in its Relay Department as a Field Supervisor, and as an Engineer in the Independent Safety Engineering Group at the Shoreham Nuclear Power Station. Lee's experience also includes design work with American Electric Power, and Sargent and Lundy Engineers. Lee received his Master of Science in electric power system engineering from the Ohio State

Name and Title	Company and Address	Contact Info	Bio
			University, and his Bachelor of Science in Electrical Engineering from Washington University in Saint Louis. Lee completed the General Electric Company Power System Engineering Course. Lee is a licensed Professional Engineer in the State of New York, and a NERC Certified System Operator--Reliability.
Farrokh (Frank) Habibi-Ashrafi, Lead Senior Egineer	Southern California Edison, Advanced Technology 14799 Chestnut St. Westminster, CA 92683	714-934-0821 Farrokh.habibiashrafi@sce.com	Dr. Farrokh Habibi-Ashrafi is a Lead Senior Engineer in the Advanced Technology Organization of Southern California Edison Company (SCE). He has been working at SCE for more than 17 years, with 10 years of it as a Senior Protection Engineer. At his present position, he is performing studies in development of Phasor Measurement Technology, and advanced protection and control applications at SCE. Prior to joining SCE, Dr. Habibi-Ashrafi was Principal Manager of the Everest Engineering Company providing Substation Engineering and Design to electric utilities in California. Dr. Habibi-Ashrafi received his Engineering degree in Electrical and Mechanical Engineering from University of Tehran, and Ph.D. in electrical engineering from University of Southern California, Los Angeles. He is a registered professional electrical engineer in State of California.

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Name and Title	Company and Address	Contact Info	Bio
Alan D. Baker	Florida Power & Light Company 700 Universe Blvd. Juno Beach , FL 33407 Mailstop: PDL/PDC	(561) 845-4861 alan.baker@fpl.com	Alan Baker graduated from University of Florida in 1981 with a BSEE degree. Alan has thirty four years of electric utility experience, primarily in protection and control engineering. He hold a P.E. license in electrical engineering from the state of Florida. Alan is currently a Principal Engineer at FP&L providing technical service support in communication, relay testing and serves as the SME for DDRs and generation protection.
Daniel J. Hansen	NRG Energy, Inc 1000 Main St. Houston, TX 77002	832-357-7271 Daniel.Hansen@nrg.com	Dan Hansen is an electrical engineer and a registered P.E. in the State of Texas. Dan received an undergraduate degree from Lamar University and a graduate degree from the University of Houston, both in electrical engineering. He has thirty-five years of experience in the field of power generation, including new plant design and construction, retrofit design for small to large projects, commissioning, operations, and maintenance support. Specific areas of expertise have included generating station protective relaying and generator excitation controls. Companies worked for include Houston Lighting & Power, Reliant Energy, RRI Energy, GenOn Energy, and NRG Energy.
Tim Kucey Manager NERC/CIP Standards & Compliance	PSEG Fossil LLC 80 Park Plaza T25B Newark NJ 07102	Timothy.kucey@pseg.com 973-430-5416	Tim Kucey joined the Project 2007-11 DM SDT in May 2013. He has 29 years of Electrical/Power Systems engineering experience in: bulk power systems; industrial and power systems monitoring and control (DCS, EMS, SCADA RTU,

Name and Title	Company and Address	Contact Info	Bio
			instruments); NERC/ERO standards and CMEP; regulatory agency permitting and oversight. He joined PSEG in his present capacity in September 2011. He was a Team Lead for the NERC 2003 Northeast Blackout Investigation, and also support to the US-Canada Power System Outage Task Force's blackout report, while a staff member of Canada's National Energy Board (NEB), from 2002 to 2005. He was a member of NERC's Compliance and Enforcement Group, from late 2005 until joining PSEG, as Manager of Enforcement & Mitigation and later Manager of NOP Development. Prior to joining the NEB Tim spent eight years (1994-2002) in technical commercial roles in the process monitoring and controls industry with GE Harris/GE Power, Fisher-Rosemount and Moore Process Automation. His start in the utility industry was with TransAlta Utilities, from mid-1985 to mid-1994, in several vertically-integrated utility engineering roles. Tim holds a Bachelor of Arts degree and a Bachelor of Engineering degree (Electrical with power systems/facilities/machines concentration) from the University of Saskatchewan, in Canada. Tim is also a current member of NPCC's PRC-002-NPCC regional reliability standard review team.

Jack Soehren Principal Engineer	ITC Holdings 27175 Energy Way Novi, Michigan 48377	248-946-3290 jsoehren@ itctransco.com	Jack Soehren is a Principal Engineer of ITC Holdings Corp. Michigan Relay Performance group a position he has held since the start of his career with ITC in June 2003. Prior to joining ITC, Jack was a Senior Engineer at Detroit Edison in the Relay Performance group. Overall, Jack was with Detroit Edison for 9 years. Jack was a member of the ReliabilityFirst PRC-002 Disturbance Monitoring drafting team and a member of the ECAR 2003 blackout Major System Disturbance Analysis Task Force. Jack has participated as a working group member within the IEEE Power System Relay Committee which produced technical reports most notably the 2004 and 2009 revisions to the report “Understanding Microprocessor-Based Technology Applied to Relaying” and the 2008 report “Performance of Relaying during Wide-Area Stressed Conditions”. Jack is a six-year veteran of the US Navy in which he served on board the USS South Carolina, CGN-37, as a mechanical operator in the nuclear powered propulsion plants. Jack received his Bachelor of Science in Electrical Engineering from the University of Michigan.
Vladimir Stanisic Senior Engineer	AESI Inc - Engineering and Management Consultants 775 Main Street East, Suite 1B, Milton, Ontario, L9T 3Z3	905-875-2075 ext. 253 vladimirs@aesi-inc.com	Vlad Stanisic has over 29 years of diverse and progressive career in planning, design, project management and construction of utility and industrial electric power systems and facilities. His expertise includes protection and controls (P&C), power generation operations and business development. He is currently with AESI Inc., Engineering and Management Consultants. His previous employers include Ontario Hydro (Ontario Power Generation) and BC Hydro

			where he served in a variety of engineering, project management and regulatory roles. Following 2003 Blackout Vlad was a key member of OPG's task force assessing the performance of the power plants prior to and following the system collapse and formulating the follow-up actions. Vlad received a Master of Electrical Engineering degree, Power Systems, from the University of Belgrade and has done postgraduate work at the University of Toronto. He is a registered professional engineer in Ontario and British Columbia, a Licensed Professional Engineer of Yugoslavia, and a member of CIGRE (Study Committee C1 – Power System Development and Economics). Vlad maintains an active role in North American electric reliability programs and initiatives.
Ryan Quint	Dominion Technical Solutions, Inc.	804-771-4850 ryan.d.quint@dom.com	Ryan Quint is a Transmission Planning Engineer with Dominion Virginia Power. His primary responsibilities include developing wide area applications and tools, events analysis, cascading analysis and simulations, and dynamic load modeling. Prior to joining DVP, Ryan worked at Bonneville Power Administration in Customer Service Engineering, Remedial Action Scheme Design, Measurement Systems Laboratory, Transmission Planning, and Long Range Transmission Planning. He is active in the power industry as a member of IEEE Power and Energy Society as well as CIGRE. Ryan is also Co-Chair of the North American Synchrophasor Initiative Engineering Analysis Task Team and Chair of the North American Transmission Forum Dynamic Load Modeling Working Group.

			Ryan received his Bachelor of Science in Electrical Engineering from University of Washington in 2010, and Master of Science and Doctor of Philosophy degrees from Virginia Tech in 2012 and 2013, respectively.
Stephen Crutchfield - Standards Developer	North American Electric Reliability Corporation 3343 Peachtree Road, NE 4th Floor East Tower – Suite 400 Atlanta, GA 30326	609-651-9455 Stephen.crutchfield@nerc.net	Stephen Crutchfield is the NERC Staff Coordinator for Project 2007-11, Disturbance Monitoring. Stephen began his career with NERC in May 2007. Prior to joining NERC, Stephen was a Project Manager with Shaw Energy Delivery Services, managing engineering and construction projects in the substation and transmission line fields. Stephen's background also includes experience with PJM as Manager of RTO Integration, working on the operations and markets integration of new members (AEP, ComEd, Dayton, Dominion and Duquesne) into PJM and southern seams operations issues with Progress Energy, Duke and TVA. Stephen also helped lead the team that was developing GridSouth in the dual roles of Organization Architect and Manager of Customer Support. Prior to GridSouth, Stephen was the Manager of Power System Operations Training at Progress Energy where he spent over 10 years training System Operators and Engineers. Overall, Stephen was with Progress Energy for 16 years. Stephen received his Bachelor of Arts in Physics from the University of Virginia and Masters of Science in Electrical Engineering from North Carolina State University. Stephen holds a Master of Science in Management degree, also from North Carolina State University.