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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PRC-002-2

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

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

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. JUSTIFICATION FOR APPROVAL

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.

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

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. <u>Proposed Requirements</u>

(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]

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[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

[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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