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-002-4

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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-002-4 (Disturbance Monitoring and Reporting Requirements).

As discussed more fully herein, proposed Reliability Standard PRC-002-4 would advance the reliability of the Bulk-Power System ("BPS")[4] by clarifying the requirements of the PRC-002 standard and eliminating potential ambiguities that could result in unnecessary or duplicative data collection burdens for entities. NERC requests that the Commission approve the proposed Reliability Standard, as shown in **Exhibit A**, as just, reasonable, not unduly discriminatory or

1 16 U.S.C. § 824o.

2 18 C.F.R. § 39.5 (2022).

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), *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

4 Unless otherwise indicated, all capitalized terms shall have the meaning used in the *Glossary of Terms Used in NERC Reliability Standards*, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf. [hereinafter NERC Glossary].

preferential, and in the public interest. NERC also requests that the Commission approve: (i) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit E**); (ii) the retirement of Reliability Standard PRC-002-3; and (iii) the proposed implementation plan (**Exhibit B**).

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of the proposed Reliability Standard, a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (**Exhibit D**), and a summary of the standard development history (**Exhibit F**). The NERC Board of Trustees adopted the proposed Reliability Standard on February 16, 2023.

This petition is organized as follows: Section I provides a summary of NERC's petition. Section II provides the individuals to whom notices and communications related to the filing should be provided. Section III provides relevant background regarding: (i) the regulatory structure governing the Reliability Standards approval process; (ii) the history of the PRC-002 Reliability Standard; and (iii) information on the development process for the proposed Reliability Standard. Section IV provides an overview and justification for the proposed Reliability Standard. Section V petition provides a summary of the proposed implementation plan, and Section VI provides the conclusion.

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5 18 C.F.R. § 39.5(a).

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. *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104 at P 262, 321-37 [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

I. OVERVIEW

Disturbance monitoring data can be used to improve the accuracy of planning and operating models and to identify risks to the BPS that might not have been previously identified. The collection of this data allows engineers to compare actual system performance with expected system performance under Disturbance conditions, thereby allowing engineers to improve the system models that are used for both planning and operating the BPS. Reliability Standard PRC-002-2, which became effective in 2016, provides a series of requirements for collecting different types of disturbance monitoring data at locations on the Bulk Electric System ("BES") and for periodically re-assessing those locations for continued validity. The standard addresses the collection of sequence of recording (SER) data, fault recording (FR) data, and dynamic Disturbance recording (DDR) data, data types which can provide useful information in analyzing system Disturbances.[7]

In the course of implementing Reliability Standard PRC-002-2, NERC identified two opportunities to improve the standard: first, by clarifying the requirements of the PRC-002 with respect to notifications and when SER or FR data is required; and second, to revisit the standard to address the impacts associated with the growing penetration of inverter-based resources on the BPS and the findings of recent event reports involving such resources. Similarly, the Commission discussed the need for improved disturbance monitoring requirements addressing the growth of

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[7] The Commission approved a revised version of the PRC-002 standard, Reliability Standard PRC-002-3, as part of a suite of Reliability Standards revisions to improve the framework for establishing and communicating System Operating Limits. *See N. Am. Elec. Reliability Corp.*, Docket No. RD22-2-000 (March 4, 2022). Reliability Standard PRC-002-3 is scheduled to become effective in 2024.

inverter-based resources on the BPS in a November 2022 Notice of Proposed Rulemaking issued in Docket No. RM22-12-000.[8]

Proposed Reliability Standard PRC-002-4, the subject of this filing, contains a number of revisions intended to clarify the standard, aid in its administration, and reduce ambiguities and unnecessary burdens. Work is currently underway to consider new or revised Reliability Standards to address the growth of inverter-based resources on the BPS.

For reasons that are discussed more fully herein, NERC respectfully requests that the Commission approve proposed Reliability Standard PRC-002-4 and the associated elements as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

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[8] *Reliability Standards to Address Inverter-Based Resources*, Notice of Proposed Rulemaking, 181 FERC 61,125 at PP 31 and 78 (2022) (stating, "The Reliability Standards do not ensure that transmission planners and operators receive disturbance monitoring data regarding all generation resources capable of having a material impact on the reliable operation of the Bulk-Power System, including IBRs, to adequately assess disturbance events (e.g., a fault on the line, a generator tripped off-line) and their behavior during those events" and proposing to "direct NERC to include technical criteria for having disturbance monitoring equipment at buses and elements of registered IBRs to ensure disturbance monitoring data is available to the planners and operators for analyzing disturbances on the Bulk-Power System and to validate registered IBR models.")

II. NOTICES AND COMMUNICATIONS

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

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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 BPS, and with the duties of certifying an 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 BPS in the United States will be subject to Commission-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 new 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.

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9 16 U.S.C. § 824o.

10 *Id.* § 824o(b)(1).

11 *Id.* § 824o(d)(5).

12 18 C.F.R. § 39.5(a).

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the BPS and to ensure that 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. NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[15]

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[16] and thus satisfy several of the Commission's criteria for approving Reliability Standards.[17] The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the comments of all stakeholders. Stakeholders must approve, and the NERC Board of Trustees must adopt, a new or revised Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

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[13] 16 U.S.C. § 824o(d)(2).

[14] 18 C.F.R. § 39.5(c)(1).

[15] The NERC Rules of Procedure, including Appendix 3A, NERC Standard Processes Manual, are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

[16] *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at P 250 (2006).

[17] Order No. 672, *supra*, at PP 268, 270.

C. History of Disturbance Monitoring Reliability Standards

Monitoring and analysis of grid Disturbances plays an important role in assuring BPS reliability. 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.

Disturbance monitoring data can be used to improve the accuracy of planning and operating models and to identify risks to the BPS that might not have been previously identified. The collection of this data allows engineers to compare actual system performance with expected system performance under Disturbance conditions, thereby allowing engineers to improve the system models that are used for both planning and operating the BPS. While the voluntary NERC standards then in effect required the use of recording devices for disturbance analysis, the investigation into the causes of the August 2003 blackout underscored the need for enhanced requirements in this area.[18]

In its initial petition for approval of Reliability Standards, NERC submitted the first version of the PRC-002 standard, PRC-002-0, for Commission approval.[19] NERC subsequently replaced this version with PRC-002-1 and PRC-018-1 in a later-filed petition in the same docket.[20] Reliability Standard PRC-002-1 would have required Regional Reliability Organizations to

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18 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) at 162 (recommending that the use of time-synchronized data records be required, recorders be promptly installed where needed on the system, and that data recording protocols be established to facilitate future monitoring and analysis).

19 *Petition of NERC for Approval of Reliability Standards*, Docket No. RM06-16-000 (Apr. 4, 2006).

20 *Petition of NERC for Approval of Proposed Reliability Standards*, Docket No. RM06-16-000 (Aug. 28, 2006).

establish requirements for installation of Disturbance monitoring equipment and reporting of Disturbance data to facilitate analyses of events and verify system models. Reliability Standard PRC-018-1 addressed installation of Disturbance monitoring equipment and data reporting. In Order No. 693, the Commission approved Reliability Standard PRC-018-1.[21] However, the Commission identified Reliability Standard PRC-002-1 as a "fill in the blank" standard that should be modified to apply to users, owners, and operators of the BPS responsible for providing information, and declined to take action on it.[22] In the order, the Commission directed NERC to consider the comments in the underlying proceeding regarding the need for greater continent-wide consistency in the PRC-002 standard.[23]

In 2014, NERC submitted a petition for approval of Reliability Standard PRC-002-2.[24] Reliability Standard PRC-002-2 consolidated disturbance monitoring requirements from PRC-002-1 and PRC-018-1 into a single Reliability Standard providing a comprehensive and continent-wide approach to Disturbance monitoring data collection. The Commission approved Reliability Standard PRC-002-2 in Order No. 814, issued in 2015.[25] The standard became effective in the United States on July 1, 2016, with later phased-in compliance dates for specific requirements.

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21 Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System* 118 FERC ¶ 61,218 at P 1551 (2007) [hereinafter Order No. 693].

22 Order No. 693 at PP 77-78 and 1455.

23 *Id.* at 1456.

24 *Petition of NERC for Approval of Proposed Reliability Standard PRC-002-2*, Docket No. RM15-4-000 (Dec. 15, 2014).

25 Order No. 814, *Disturbance Monitoring and Reporting Requirements Reliability Standard*, 152 FERC ¶ 61,198 (2015).

In 2021, NERC submitted Reliability Standard PRC-002-3 for Commission approval as part of a larger suite of Reliability Standards revisions for improving the framework for establishing and communicating System Operating Limits.[26] This version of the standard modifies the applicability of the PRC-002 standard to remove Planning Coordinators as a responsible entity and replace any references to the Planning Coordinator with the Reliability Coordinator. The Commission approved Reliability Standard PRC-002-3 in March 2022.[27] It is scheduled to become effective in the United States on April 1, 2024 under the approved implementation plan.

D. Project 2021-04 Modifications to PRC-002

NERC initiated Project 2021-04 Modifications to PRC-002 in 2021 to address two Standard Authorization Requests concerning the PRC-002 standard. The first of the two requests sought revisions to clarify certain provisions in the standard, including those regarding notifications and when an applicable owner is required to have disturbance monitoring data. The second of the two requests sought revisions to the PRC-002 standard to better account for the growth of inverter-based resources on the BPS. NERC determined to address the two separate requests as part of a single, two-phase standard development project. Proposed Reliability Standard PRC-002-4 represents the conclusion of the first phase of work under this project and provides necessary clarifications and revisions to the standard regarding notifications for and requirements for disturbance monitoring data.[28]

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26 *Petition of NERC for Approval of Proposed Reliability Standards Related to Establishing and Communicating System Operating Limits*, Docket No. RD22-2-000 (June 28, 2021).

27 *N. Am. Elec. Reliability Corp.*, Docket No. RD22-2-000 (Mar. 4, 2022).

28 In response to one entity's comments, the drafting team revised the Standard Authorization Request for this first phase to include the following as a project goal: "If appropriate, add Planning Coordinator to the Western

The first draft of proposed Reliability Standard PRC-002-4 and the associated implementation plan were posted for formal comment period and ballot from June 9, 2022 through July 25, 2022. The proposed Reliability Standard received 66.9% approval, with 87.24% quorum. The proposed implementation plan received 75.89% approval with 88.15% quorum. The second draft of the proposed Reliability Standard and the associated implementation plan were posted for an additional formal comment period and ballot from September 26, 2022 through November 14, 2022.[29] The final draft of the proposed Reliability Standard and the associated implementation plan were posted for final ballot from December 7, 2022 through December 16, 2022. The proposed Reliability Standard received 96.43% approval, with 83.79% quorum. The proposed implementation plan received 96.11% approval, with 84.32% quorum.

The NERC Board of Trustees adopted the proposed Reliability Standard and the associated elements on February 16, 2023. A summary of the development history and the complete record of development is attached to this petition as **Exhibit F**.

IV. JUSTIFICATION FOR APPROVAL

In this petition, NERC submits for Commission approval proposed Reliability Standard PRC-002-4 (Disturbance Monitoring and Reporting Requirements). The purpose of the proposed Reliability Standard, which remains unchanged from the currently effective version, is to have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances. As noted

Interconnection in Section 4.1.3 as a possible Responsible Entity." See Exhibit F Complete Record of Development at item 14 (Revised Glencoe Light Standard Authorization Request).

During the process of developing proposed PRC-002-4, the standard drafting team consulted with other entities in the Western Interconnection and determined it was not appropriate to make this applicability change. *See* Exhibit F Complete Record of Development at item 25, p. 87 (September 2022 Consideration of Comments) ("In all interconnections, per applicability in 4.1.1, the standard applies to Reliability Coordinator. Not sure why planning coordinator is also sending notifications unless it is done on behalf of the reliability coordinator. Based on applicability in the standard, the reliability coordinator is ultimately responsible.")

[29] The ballot was extended to reach quorum.

above, the collection of this data allows engineers to compare actual system performance with expected system performance under Disturbance conditions, thereby allowing engineers to improve the system models that are used for both planning and operating the BPS.

Proposed Reliability Standard PRC-002-4 would advance the reliability of the BPS by providing needed clarity regarding the application of the standard's requirements. First, proposed Reliability Standard PRC-002-4 would clarify requirements for notifications under the standard, including when Generator Owners and Transmission Owners must have data for an applicable transformer or transmission line. Second, the proposed Reliability Standard clarifies and promotes consistency in terminology used in the standard. Third, the proposed Reliability Standard brings the implementation timeframe for newly-identified facilities into the standard. Last, the proposed Reliability Standard adds a criterion that defines what constitutes a substantial change in fault current levels that would require changing the locations for which sequence of events (SER) and fault recording (FR) data is recorded. The revisions and supporting rationale are discussed in further detail below.

As discussed in **Exhibit D**, proposed Reliability Standard PRC-002-4 meets the Commission's criteria for approval in Order No. 672 and is just, reasonable, not unduly discriminatory, and in the public interest. NERC respectfully requests that the Commission approve the proposed Reliability Standard to become effective in accordance with the proposed implementation plan discussed in Section V.

A. Transmission Owner Notification Requirements

Requirement R1 of the PRC-002 Reliability Standard requires each Transmission Owner to: (1) identify BES buses for which SER and FR data is required, using the methodology in Attachment 1 (Requirement R1 Part 1.1); (2) notify other owners of BES Elements connected to the identified buses that SER or FR data is required (Requirement R1 Part 1.2); and (3) re-evaluate all BES buses at least once every five years and notify owners of connected BES Elements when SER or FR data will be required (Requirement R1 Part 1.3). Proposed Reliability Standard PRC-002-4 improves upon approved Reliability Standard PRC-002-3 by clarifying these requirements. Proposed Reliability Standard PRC-002-4 revises Requirement R1 as follows:

> **R1**. Each Transmission Owner shall:
>
> **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-~~3~~4, Attachment 1.
>
> **1.2.** Notify other owners of BES Elements directly connected[1] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER and FR data. ~~, if any,~~ This notification is required 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 Part 1.2 contains several revisions. First, the revised Requirement Part provides clarity regarding the BES Elements that will require data. Requirement R1 Part 1.2 introduces the phrase "directly connected" to refer to those BES Elements that will require data for the BES buses identified under Part 1.1. New footnote 1 clarifies that, for purposes of this standard, "directly connected" BES Elements means "BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded."

The proposed revisions to Requirement R1 Part 1.2, shown in redline above, are intended to clarify the notification requirements of Requirement R1. Under the currently effective PRC-

002-2 Requirement R1, notifications for SER/FR data are being sent to BES Element owners that extend well beyond the BES bus boundary described in PRC-002 Attachment 1 as "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." (*See* Attachment 1 Step 1). These notifications would then trigger the data recording requirements of the standard. The proposed inclusion of the phrase "directly connected" in Requirement R1 Part 1.2, with the meaning in the proposed footnote 1, would clarify that these notifications should be made consistent with the boundaries of a "single BES bus" specified in Attachment 1. The exclusion of transformers that have a low-side operating voltage of less than 100 kV from the phrase "directly connected" is consistent with Requirement R3 Part 3.2, which specifies that Transmission Owners and Generator Owners shall have FR data to determine phase current and the residual or neutral current for transformers that have a low-side operating voltage of 100 kV or above. These changes would clarify the extent of the required notifications and data collection requirements consistent with other provisions in the currently effective and approved versions of the PRC-002 standard.

Second, proposed Requirement R1 Part 1.2 is revised to provide that the Transmission Owner shall make notifications to owners of other BES Elements directly connected to the identified BES buses that data is required only where the Transmission Owner does not already have the data. This revision would improve the efficiency of the standard by lessening duplication in FR/SER data collection and thereby avoiding unnecessary burdens and costs being imposed on applicable entities.

Third, proposed Requirement R1 Part 1.2 contains several non-substantive revisions intended to improve readability.

Requirement R1 Part 1.3 is revised to remove reference to implementing a list of re-evaluated BES buses according to the implementation plan. As discussed in further detail in the following section, proposed Reliability Standard PRC-002-4 would move requirements for implementing a re-evaluated list of BES buses from the PRC-002 implementation plan to a new requirement, Requirement R13.

B. Proposed Requirement R13

Proposed Requirement R13 is a new requirement that would carry forward a provision, presently in the implementation plans for Reliability Standard PRC-002-2 and PRC-002-3, regarding the time period to address new designations of BES Elements identified under Requirement R1 (pertaining to SER or FR data) or Requirement R5 (pertaining to dynamic Disturbance recording (DDR) data). The implementation plan for approved Reliability Standard PRC-002-3 provides that "entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the T[ransmission] O[wner] or the R[eliability] C[oordinator]." Proposed Requirement R13 would move that timeframe into a new mandatory and enforceable standard requirement, as follows:

> **R13**. Each Transmission Owner and Generator Owner shall:
>
> **13.1**. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.
>
> **13.2**. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

For clarity and consistency with other NERC Reliability Standards, the timeline of "three (3) years" in the implementation plan is revised to "three (3) calendar years" under proposed Requirement R13. The phrase "calendar months" or "calendar years" is used in multiple NERC

Reliability Standards to refer to the timing that is required for a specific activity[30] and is well understood by industry.

As noted above, conforming changes are proposed in Requirement R13 to remove reference to the implementation plan. Similar conforming changes are also proposed in Requirement R5 Part 5.4.

C. Revisions to Attachment 1

Attachment 1 to the PRC-002 Reliability Standard provides the methodology for selecting buses for capturing SER and FR data in accordance with Requirement R1. Proposed Reliability Standard PRC-002-4 improves upon the approved version by defining a criterion by which entities may evaluate whether a change in fault current level requires changing SER and FR data as part of a re-evaluation under Requirement R1 Part 1.3.

Under the methodology defined in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1.

To avoid imposing undue cost or compliance burdens that are unnecessary for reliability, the PRC-002-4 standard drafting team established a threshold under which a change in the

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30 *See, e.g.*, Reliability Standards CIP-002-5.1a (Cyber Security – BES Cyber System Categorization), BAL-005-1 (Balancing Authority Control), EOP-005-3 (System Restoration from Blackstart Resources), MOD-027-1 (Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions), and TPL-007-4 (Transmission System Planned Performance for Geomagnetic Disturbance Events).

applicable BES bus would not be required as part of the required re-evaluation. This criterion is added in Attachment 1 Step 7, which is revised to read as follows:

> 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.
>
> <u>During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.</u>
>
> **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.

The selection of 15 percent as the appropriate threshold is consistent with Reliability Standard PRC-027-1 Requirement R2 Option 2, which requires a Protection System coordination study when the fault current deviation is 15 percent or greater from an established baseline. The PRC-027 standard drafting team established the 15 percent threshold based on generally accepted margins used in Protection System settings.[31] The PRC-002-4 standard drafting team determined that 15 percent was a technically justified threshold for the PRC-002 Attachment 1 analysis as well.

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[31] *See* Reliability Standard PRC-027-1 (Coordination of Protection Systems for Performance During Faults), Supplemental Material at 12, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-027-1.pdf. The Commission approved Reliability Standard PRC-027-1 in Order No. 847, issued June 7, 2018 in Docket No. RM16-22-000. *Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Reliability Standards,* 163 FERC ¶ 61,184 (2018).

D. Other Revisions

In addition to the revisions discussed above, NERC proposes several other revisions in proposed Reliability Standard PRC-002-4. First, to promote consistency throughout the standard, the clarified phrase "directly connected," discussed in Section IV.A above in the context of required notifications under Requirement R1, is carried forward in Requirements R2 and R3. Second, proposed Requirement R5 is revised to remove the extraneous phrase "when requested" from Requirement R5 Part 5.3, and to clarify that the Reliability Coordinator is required to re-evaluate all BES Elements "within its Reliability Coordinator Area" under Requirement R5 Part 5.4. Third, Requirement R8 clarifies that the date by which new installations of equipment for DDR data must have continuous data recording and storage is the effective date of Reliability Standard PRC-002-2, the version of the PRC-002 standard that introduced this requirement. This change is needed to avoid resetting this benchmark date each time a subsequent version of the PRC-002 standard becomes effective. Fourth, and last, proposed Reliability Standard PRC-002-4 contains a number of revisions to the compliance elements, intended to conform this version of the standard to the latest NERC Reliability Standard template. These revisions are shown in clean and in redline in Exhibit A.

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the implementation plan attached to this petition as **Exhibit B**. The proposed implementation plan provides that proposed Reliability Standard PRC-002-4 would become effective on the later of: (1) the first day of the first calendar quarter following regulatory approval; or (2) the effective date of Reliability Standard PRC-002-3.[32] The version of the PRC-002 Reliability Standard then in effect would be

[32] Reliability Standard PRC-002-3 is scheduled to become effective in the United States on April 1, 2024.

retired immediately prior to the effective date of Reliability Standard PRC-002-4. This implementation timeline reflects consideration of the fact that the revisions to Requirements R1, R3, and R5 are clarifying in nature, and that Requirement R13 simply relocates the implementation time period prescribed in the implementation plans for previous versions of the PRC-002 standard. The implementation timeframe also reflects consideration that a version of the PRC-002 standard, Reliability Standard PRC-002-3, has been approved by the Commission and is pending enforceability. The proposed implementation plan appropriately balances the need for implementation against the time required for compliance and is therefore reasonable under the criteria set forth by the Commission in Order No. 672.[33]

[33] *See* Order No. 672 at P 333 ("In considering whether a proposed Reliability Standard is just and reasonable, the Commission 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.")

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve, as just, reasonable, not unduly discriminatory, and in the public interest:

- Proposed Reliability Standard PRC-002-4, and the associated elements, as shown in **Exhibit A;**
- the retirement of the version of the PRC-002 Reliability Standard that would then be in effect (PRC-002-2 or PRC-002-3); and
- The implementation plan included in **Exhibit B**.

Respectfully submitted,

/s/ Lauren A. Perotti

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March 10, 2023

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A

Proposed Reliability Standard PRC-002-4

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-1

PRC-002-4 Clean

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal comment period with ballot	06/09/2022 – 07/15/2022
45-day formal or informal comment period with additional ballot	09/26/2022 – 11/09/2022
10-day final ballot	12/07/2022 – 12/16/2022
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

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

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Owner

   4.1.3. Generator Owner
5. **Effective Date:** 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-002-4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[1] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-4, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected 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]*

[1] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

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 directly 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 100 kV 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 Reliability Coordinator 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 Reliability Coordinator'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.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area 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.

M5. The Reliability Coordinator 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 Reliability Coordinator 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 the Reliability Standard PRC-002-2[2] and is not capable of continuous recording, triggered records

[2] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

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 Reliability Coordinator, 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 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

1.2. As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards. **Data 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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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 Enforcement Program:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None.

Violation Severity Levels

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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar	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 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 owners that their BES Elements require SER or FR data by greater than	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	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 number of specified 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 electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified 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 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 Elements and the number of specified electrical	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 electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	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 Reliability Coordinator 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 Reliability Coordinator 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.	The Reliability Coordinator 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 Reliability Coordinator 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	The Reliability Coordinator 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 Reliability Coordinator 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	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator 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 Requirement R7, Parts 7.1 through 7.4 that covers	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.

			more than 80 percent, but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	70 percent, but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	60 percent, but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
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	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner failed to have time synchronization per

			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.	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.	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.	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 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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

			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, 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, 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, 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 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.

R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-4: Implementation Plan.

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.

NERC Reliability Standard PRC-002-4: Technical Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	TBD	TBD	Revised under Project 2021-04

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.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

<u>If the list has more than 11 BES buses:</u> 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

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	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

Requirement	Entity	Implementation
R13	TO | GO	X

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-2

PRC-002-4 Redline to Last Approved

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	06/09/2022 – 07/15/2022
45-day formal or informal comment period with additional ballot	09/26/2022 – 11/09/2022
10-day final ballot	12/07/2022 – 12/16/2022
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-~~3~~4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
5. **Effective Date:** 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-~~3~~4, Attachment 1.

1.2. Notify other owners of BES Elements directly connected[1] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER and FR data. ~~,~~ ~~if any,~~ This notification is required 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 for Requirement R1, Part 1.1 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-~~3~~4, Attachment 1;~~,~~ has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement

[1] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

R1, Part 1.3. ~~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 directly 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 directly 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 Reliability Coordinator 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 Reliability Coordinator'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 within its Reliability Coordinator Area 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 Reliability Coordinator 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 Reliability Coordinator 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 the Reliability Standard PRC-002-2[2] ~~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
○ 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 at least 960 samples per second.

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

[2] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

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 Reliability Coordinator, 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards. ~~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~~ Data 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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.~~

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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~~ Enforcement Program:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None

Violation Severity Levels

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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10-calendar days, but less than or equal to 20- calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20-calendar days, but less than or equal to 30 -calendar days.	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 that their BES Elements require SER or FR data by 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 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 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 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 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 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 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 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator 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	The Transmission Owner had DDR data as directed by	The Transmission Owner had DDR data as directed by	The Transmission Owner failed to have DDR data as

			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.	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.	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.	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 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	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	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	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the

			properties as specified in Requirement R9.	recording properties as specified in Requirement R9.	total recording properties as specified in Requirement R9.	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 11.2~~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	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2~~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	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2~~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	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2~~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.

			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.	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.	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.	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 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.

R13.	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-4: Implementation Plan.~~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.

NERC Reliability Standard PRC-002-4: Technical Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	**TBD**	**TBD**	Revised under Project 2021-04

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.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. 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

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	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

Requirement	Entity	Implementation
R13	TO | GO	X

Exhibit B

Implementation Plan

Implementation Plan

Project 2021-04 Modifications to PRC-002
Reliability Standard PRC-002-4

Applicable Standard(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Requested Retirement(s)

- PRC-002-3 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner
- Generator Owner

General Considerations

This implementation plan provides that Reliability Standard PRC-002-4 will become effective on the later of: (1) the first day of the first calendar quarter following regulatory approval; or (2) the effective date of PRC-002-3.[1] Additional time to implement this version of Reliability Standard PRC-002-4 is not provided because:

- the revisions to Requirements R1, R3, and R5 are clarifying in nature, and
- the new Requirement R13 simply relocates implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself, and clarifies the implementation time, which was "three years" in the PRC-002-2 implementation plan, to "three calendar years."[2]

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard or as otherwise provided for by the applicable governmental authority; **or** (2) the effective date of PRC-002-3.

[1] In the latter case, Reliability Standard PRC-002-4 will supersede PRC-002-3 prior to it ever becoming effective.
[2] PRC-002-2 and PRC-002-3, Implementation Plans: "Entities shall be 100 percent compliant with new BES [Bulk Electric System] Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator."

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction; **or** (2) the effective date of PRC-002-3.

Retirement Date

The version of Reliability Standard PRC-002 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-002-4.

Prior Implementation Plan

The following element of the Implementation Plan for PRC-002-3 is incorporated herein and modified in case PRC-002-3 is superseded by PRC-002-4:

Reliability Coordinators in the Eastern Interconnection shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3 or six (6) months of the effective date of PRC-002-4, whichever occurs first.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C

Technical Rationale

Technical Rationale for Reliability Standard PRC-002-4

April 2022

PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator 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 Requirement 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 Disturbance Monitoring Standard Drafting Team'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-002-4, 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.

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.
5. 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 the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.
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.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B and C are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1600 MVA, 1500 MVA and 1550 MVA respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1550 MVA, 1675 MVA and 1600 MVA respectively. The bus B is the one with highest maximum three phase short circuit MVA now. The three phase short circuit MVA of bus B is within 15% of the three phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1500 MVA, 1750 MVA and 1650 MVA respectively. The three phase short circuit MVA of bus B is greater than 15% of three phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

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 requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of “directly connected” BES Elements are notified. For the purposes of this standard, “directly connected” BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 1 and 2 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

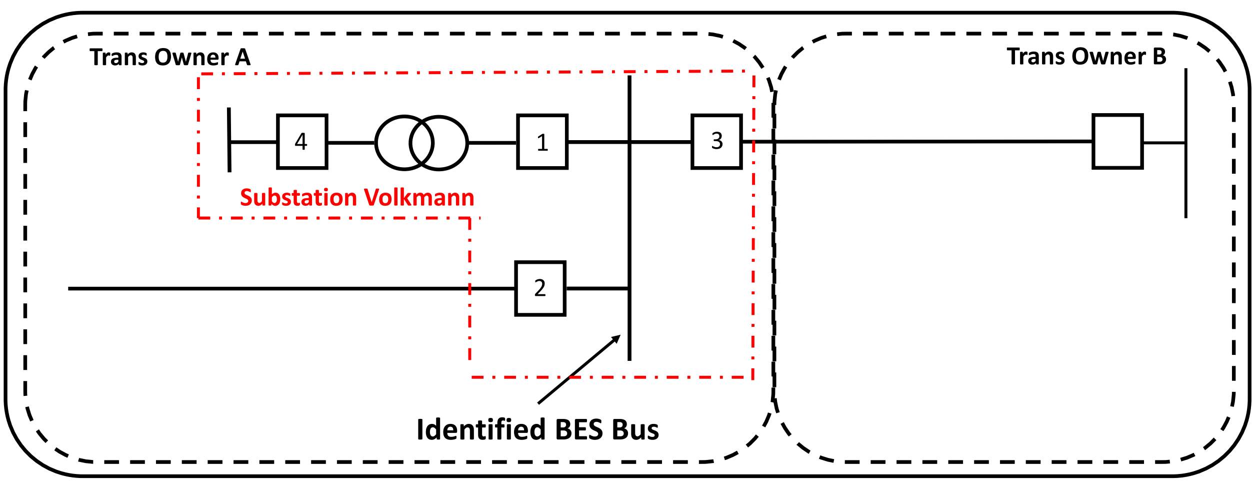

Figure 1: Straight Bus Configuration – Single Owner

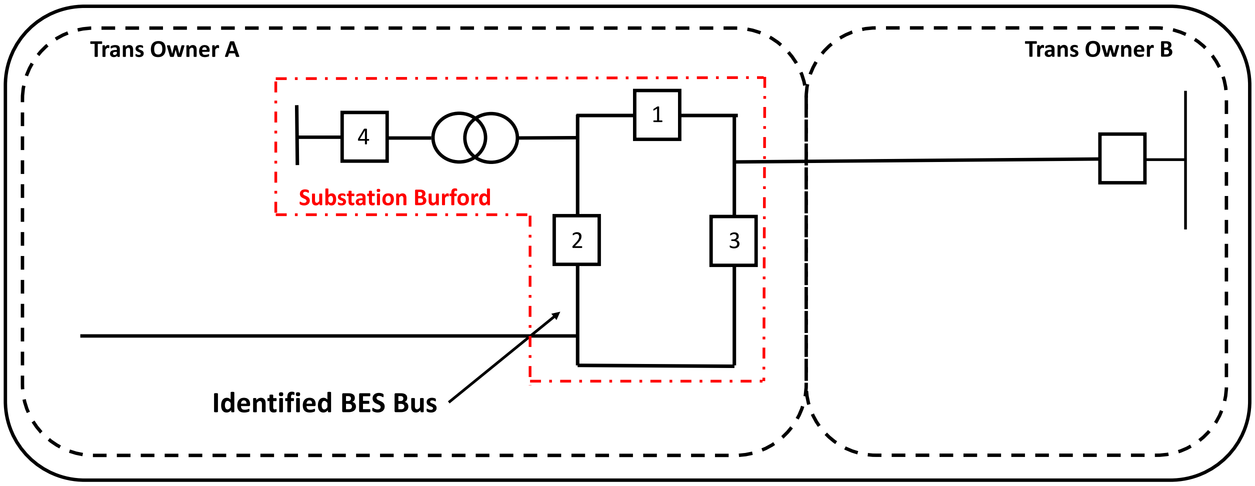

Figure 2: Ring Bus Configuration – Single Owner

Figures 3 and 4 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

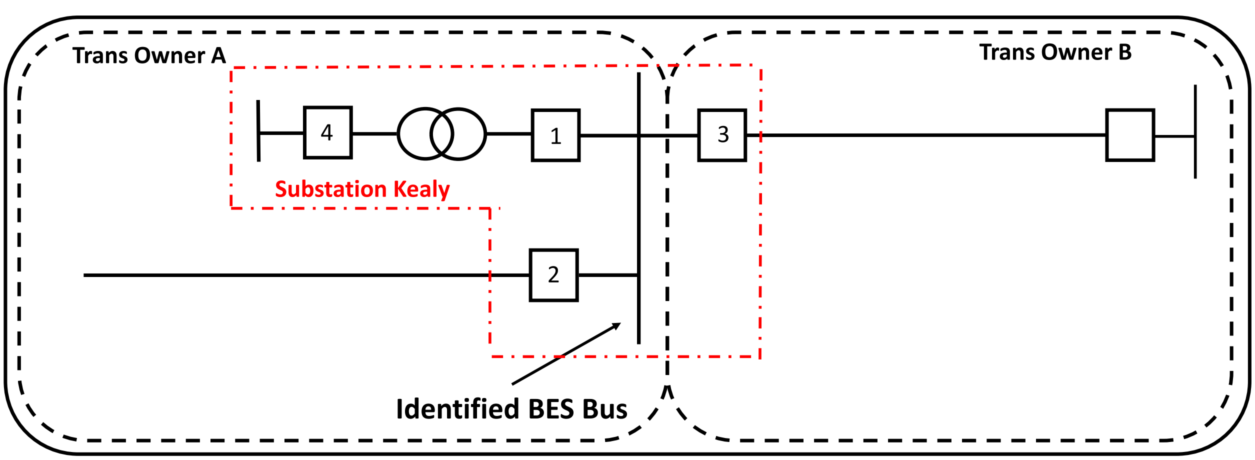

Figure 3: Straight Bus Configuration – Multiple Owners

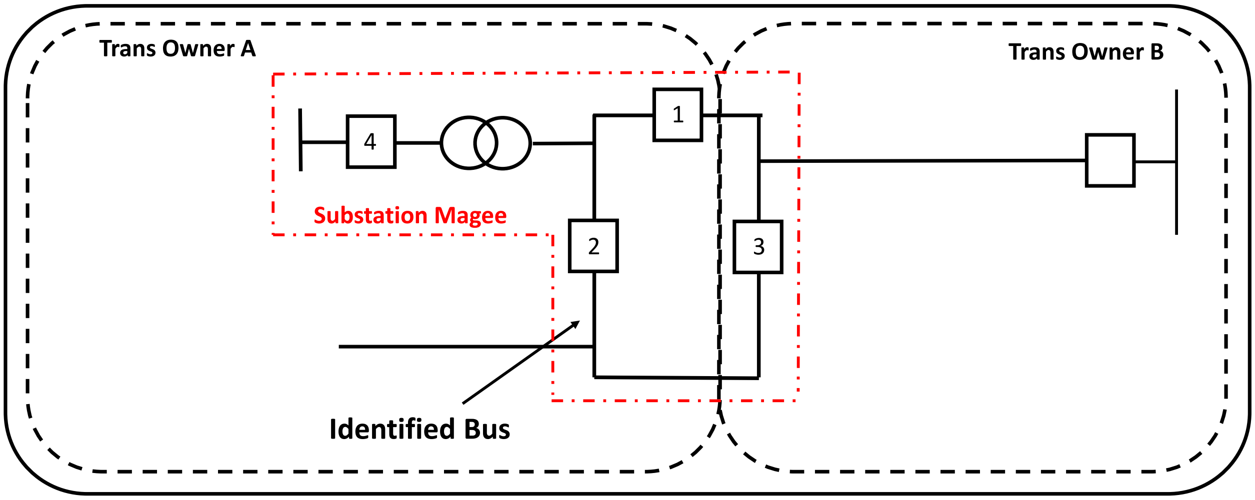

Figure 4: Ring Bus Configuration – Multiple Owners

For examples in Figures 3 and 4, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 5 shows an example with a generator interconnection. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

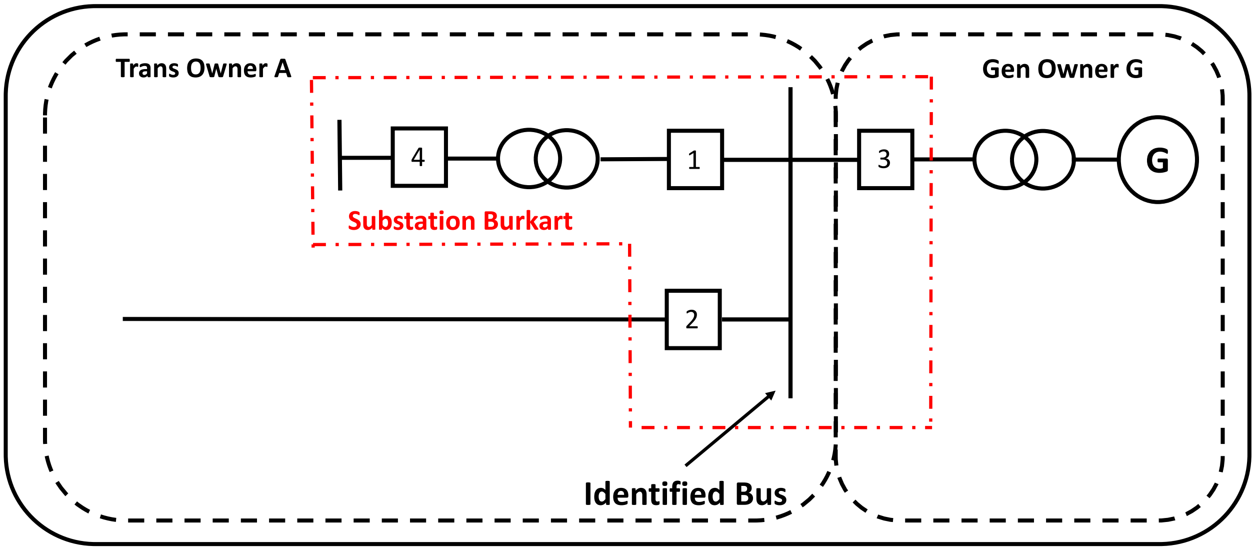

Figure 5: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 6, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

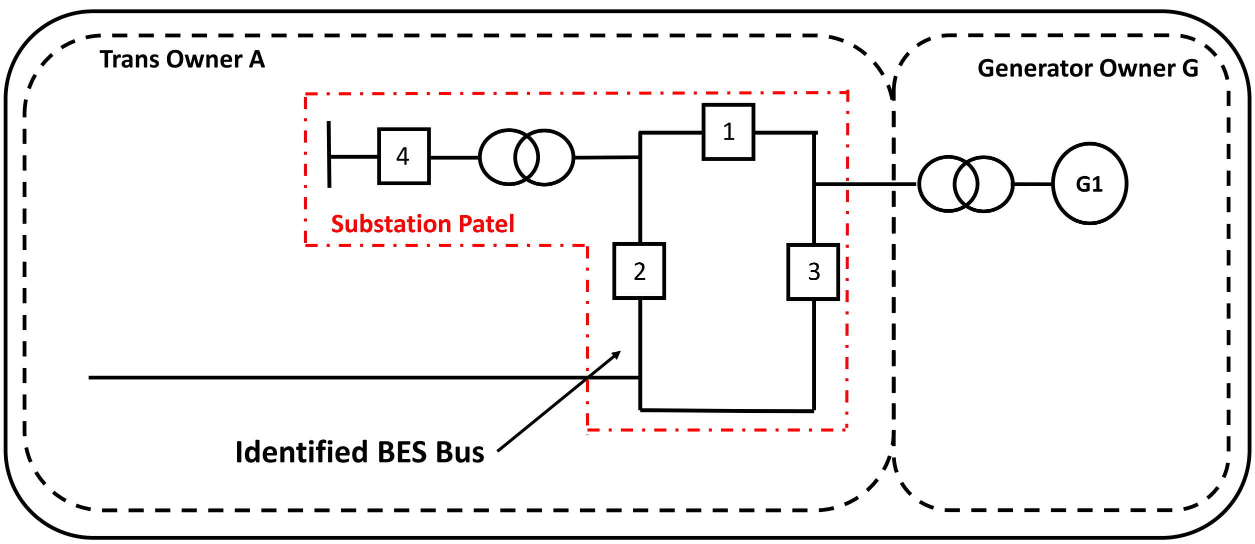

Figure 6: Generator Interconnection to Ring Bus

Figure 7 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical

bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

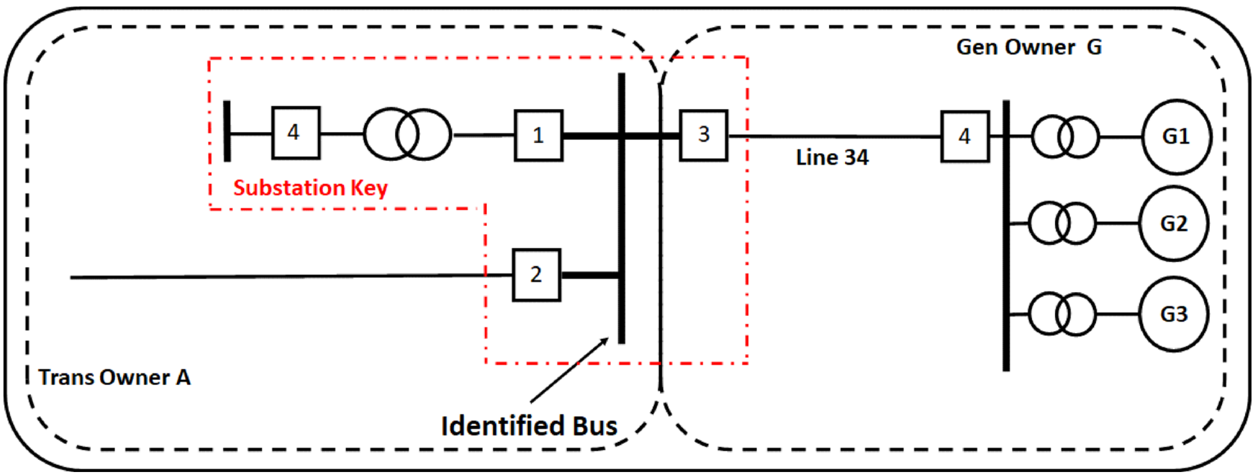

Figure 7: Generator Interconnection via Line 34

Figure 8 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3 and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

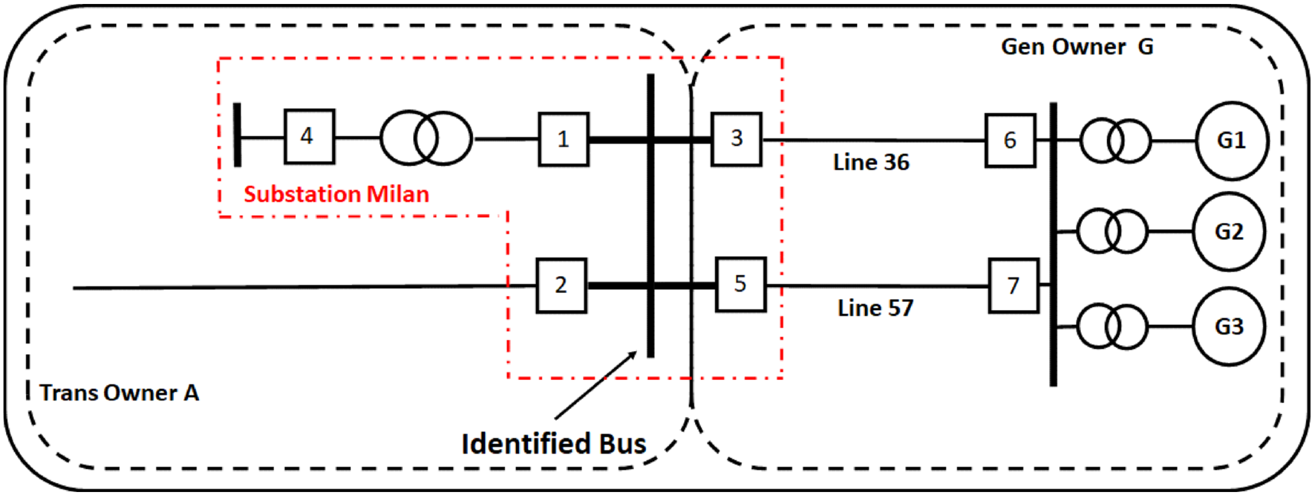

Figure 8: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification_TransmissionOwnerB

Greetings,

In accordance with NERC Standard PRC-002-4, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

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.

Rationale for Requirement 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 directly connected to a BES bus. Change of state of circuit breaker position and 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.

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.

Examples in Figures 9, 10 and 11 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement 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.

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 directly 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 directly 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.

Examples in Figures 9, 10, and 11 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

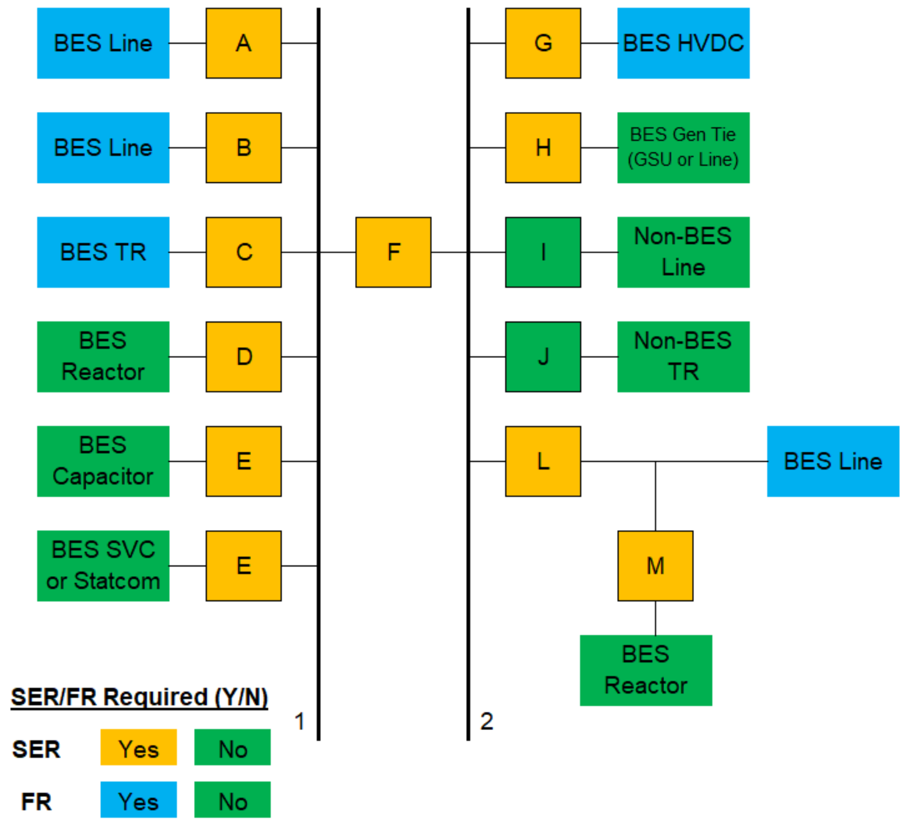

Figure 9: Straight BES Buses

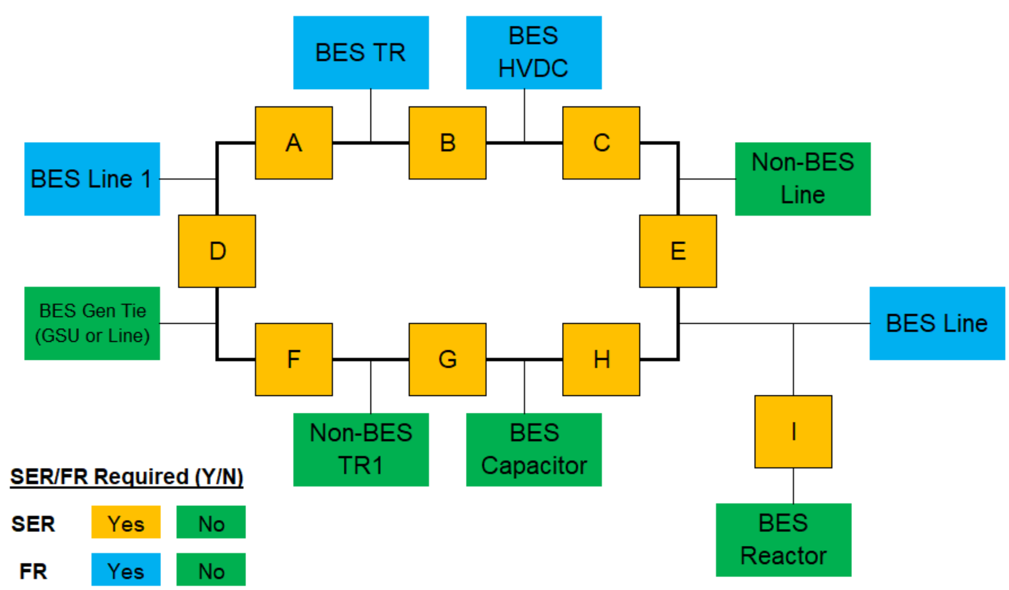

Figure 10: Ring BES Bus

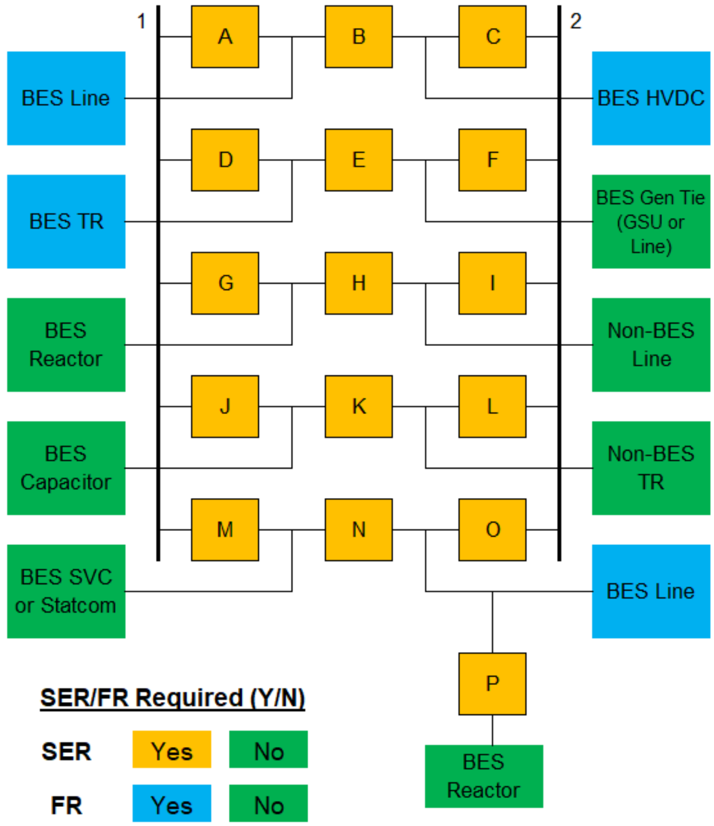

Figure 11: Breaker and Half BES Bus

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.

<u>Voltage Recordings</u>
Voltages are to be recorded or accurately determined at applicable BES buses

Rationale for Requirement 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.

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.

Rationale for Requirement 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 Reliability Coordinator 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 Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator 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 Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator 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 Reliability Coordinators, each Reliability Coordinator 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 Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator 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 Reliability Coordinators. It is intended that each Reliability Coordinator 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.

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 Reliability Coordinator 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 Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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.).

Rationale for Requirement 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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

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 Reliability Coordinator 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-002-4 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.

Rationale for Requirement 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.

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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement 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).

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.

Rationale for Requirement 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.

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.

Rationale for Requirement 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.

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 one millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement 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 11.2, 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. A10-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.

This requirement directs the applicable entities, upon requests from the Reliability 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 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 11.2 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 11.1 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 synchrophasor 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.

Rationale for Requirement 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.

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.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

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Exhibit D

Order No. 672 Criteria

EXHBIIT D

Order No. 672 Criteria

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 Standards have 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]

Disturbance monitoring data can be used to improve the accuracy of planning and operating models and to identify risks to the BPS that might not have been previously identified. Reliability Standard PRC-002-2, which first became effective in 2016, provides a series of requirements for collecting different types of disturbance monitoring data at locations on the Bulk Electric System ("BES") and for periodically re-assessing those locations for continued validity. The standard addresses the collection of sequence of recording (SER) data, fault recording (FR) data, and dynamic Disturbance recording (DDR) data, data types which can provide useful information in

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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, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) [hereinafter Order No. 672].

2 *See* Order No. 672, *supra* note 1, 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.").

See Order No. 672, *supra* note 1, 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.").

analyzing system Disturbances. The proposed Reliability Standard (proposed Reliability Standard PRC-002-4) would advance the reliability of the Bulk-Power System by: (i) clarifying requirements for notifications under the standard, including when Generator Owners and Transmission Owners must have data for an applicable transformer or transmission line; (ii) clarifying and promoting consistency in terminology used in the standard; (iii) bringing the implementation timeframe for newly-identified facilities into the standard; and (iv) adding a criterion that defines what constitutes a substantial change in fault current levels that would require changing the locations for which sequence of events (SER) and fault recording data is recorded. NERC developed the proposed standard to address the first of two Standard Authorization Requests ("SARs) concerning recommended improvements and clarifications to the PRC-002 standard. Proposed Reliability Standard PRC-002-4 is designed to achieve a specific reliability goal and contain a technically sound means to achieve that goal.

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 is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The new requirement in proposed Reliability Standard PRC-002-4 would apply to Transmission Owners and Generator Owners (R13). The applicability of the revised requirements in proposed Reliability Standard PRC-002-4 would remain unchanged. The proposed Reliability Standard clearly articulates the actions that applicable entities must take to comply with the standards.

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3 *See* Order No. 672, *supra* note 1, at P 322 ("The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.").

See Order No. 672, *supra* note 1, 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.").

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]

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, as discussed further in Exhibit E. The assignment of the severity level for each VSL is consistent with the corresponding requirement, and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

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

The proposed Reliability Standard contains measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements would be enforced and help ensure that the requirements would be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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[4] *See* Order No. 672, *supra* note 1, 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.").

[5] *See* Order No. 672, *supra* note 1, 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.").

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 goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard would achieve the reliability goal of providing needed clarity regarding the application of the standard's requirements.

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 proposed Reliability Standard contains a number of revisions that would clarify the standard, aid in its administration, and reduce ambiguities and unnecessary burdens for Generator Owners and Transmission Owners.

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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6 *See* Order No. 672, *supra* note 1, 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.").

7 *See* Order No. 672, *supra* note 1, 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 the Commission 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.").

See Order No. 672, *supra* note 1, 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 *See* Order No. 672, *supra* note 1, 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 model but should take into account geographic variations in grid characteristics, terrain, weather, and other such

The proposed Reliability Standard would continue to apply consistently throughout North America and does not favor one geographic area or regional model. The proposed Reliability Standard would provide sufficient flexibility to accommodate regional/geographic variations, including climate, generation type, market issues, state rules, and other considerations.

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

The proposed Reliability Standard would have no undue negative effect on competition and would not unreasonably restrict the available transmission capacity or limit the use of the BPS in a preferential manner. The proposed standards would require the same performance by each of the applicable entities.

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

The proposed effective date for the proposed Reliability Standard is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures or other relevant capability. The proposed implementation plan provides that the proposed Reliability Standards would become effective on the later of: (1) the first day of the first calendar quarter following regulatory approval; or (2) the effective date of Reliability Standard PRC-002-

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 *See* Order No. 672, *supra* note 1, at P 332 ("As directed by section 215 of the FPA, the Commission 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.").

10 *See* Order No. 672, *supra* note 1, at P 333 ("In considering whether a proposed Reliability Standard is just and reasonable, the Commission 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.").

3. [11] The version of the PRC-002 Reliability Standard then in effect would be retired immediately prior to the effective of PRC-002-4. This implementation timeline reflects consideration of the fact that the revisions Requirements R1, R3, and R3 are clarifying in nature, and that Requirement R13 simply relocates the implementation time period prescribed in the implementation plans for previous versions of the PRC-002 standard. The implementation timeline also reflects consideration that a version of the PRC-002 standard, Reliability Standard PRC-002-3, has been approved by the commission and is pending enforceability. The proposed implementation plan is attached as **Exhibit B** to this petition.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. **Exhibit F** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard. These processes included, among other things, 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] Reliability Standard PRC-002-3 is scheduled to become effective in the United States on April 1, 2024.

[12] *See* Order No. 672, *supra* note 1, 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 the Commission.").

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of this proposed Reliability Standard. No comments were received that indicated that the proposed Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

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[13] *See* Order No. 672, *supra* note 1, 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.").

[14] *See* Order No. 672, *supra* note 1, 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.").

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Exhibit E

Analysis of Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002-3

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. Each requirement is assigned a VRF and a VSL. 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 in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

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.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect 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

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs 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 VRF 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.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance
Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties
A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement
VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

PRC-002-4

VRF Justification for PRC-002-4, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

VSL Justifications for PRC-002-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less).
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do 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 VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-4, Requirement R2
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R2
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R3
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R3
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R4
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R4
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	OR The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days but less than or equal to 20 calendar days.	OR The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

VSL Justifications for PRC-002-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less).
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-4, Requirement R5	
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 VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-4, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R6
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R7
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R7
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R8
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R8
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R9
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R9
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R10
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R10
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R11
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R11
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justifications for PRC-002-4, Requirement R13	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R13 is consistent with those of other requirements to have DDR, SER, or FR data in the proposed Reliability Standard.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-002-4, Requirement R13			
Lower	**Moderate**	**High**	**Severe**
	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

VSL Justifications for PRC-002-4, Requirement R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-4, Requirement R13	
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	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit F

Summary of Development History and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standard PRC-002-4.

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 ("SDT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2021-04 SDT members is included in **Exhibit G**.

II. Standard Development History

A. Standard Authorization Request Development

There are two Standard Authorization Requests ("SARs) related to PRC-002, each to be addressed in separate phases of Project 2021-04 Modifications to PRC-002-2. The first SAR, which was addressed in phase 1 of this project and is the subject of this filing, was submitted by Glencoe Light and Power and sought revisions to clarify existing requirements based on industry experience. The NERC Inverter-based Resource Performance Task Force ("IRPTF") submitted the second SAR. IRPTF performed a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements. The IRPTF documented their findings the March 2020 white paper, IRPTF *Review of NERC Reliability Standards White Paper*. The IRPTF SAR focuses on revisions needed in light of growing penetration of inverter-based

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[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2).

[2] The NERC *Standard Processes Manual* is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

resources. On January 20, 2021, the Standards Committee accepted both SARs for Project 2021-04 Modifications to Disturbance Monitoring and Reporting Requirements. The Standards Committee also accepted the recommendation from the SAR DT to proceed with this project in two phases governed by the two separate SARs. The first phase addressed the Glencoe Light SAR and the second phase, which is ongoing, addresses the NERC IRPTF SAR. The Standards Committee authorized posting the Glencoe Light SAR for a 30-day formal comment period and the IRPTF SAR for a 30-day informal comment period, each running from June 14, 2021 through July 13, 2021 and authorized the solicitation of SDT members.[3] The member solicitation period was extended through July 10, 2021. On September 23, 2021 the Standards Committee appointed the Project 2021-04 Modifications to PRC-002 SAR DT.[4] On January 19, 2022, the Standards Committee accepted both SARs, as revised by the standard drafting team, and authorized drafting revisions to the PRC-002 standard.

B. First Posting - Comment Period, Initial Ballot, and Non-binding Poll – Phase I

On May 18, 2022, the Standards Committee authorized the initial posting of proposed Reliability Standard PRC-002-4, the associated Implementation Plan and other associated documents for a 45-day formal comment period and initial ballot.[5] The formal comment period took place from June 9, 2022 through July 25, 2022, with a parallel initial ballot and non-binding poll on the Implementation Plan held during the last 10 days of the comment period from July 15, 2022 through July 25, 2022. The initial ballot for proposed Reliability Standard PRC-002-4

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3 *See* NERC Standards Committee January 19, 2022 Agenda Package, Agenda Item 5. https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_Agenda_Package_January_19_2022.pdf.

4 *See* NERC Standards Committee September 23, 2021 Agenda Package, Agenda Item 6. https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_Agenda_Package_September_23_2021.pdf.

5 *See* NERC Standards Committee May18, 2022 Agenda Package, Agenda Item 5. https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_Agenda_Package_May_18_2022.pdf.

received 66.9 percent approval, reaching quorum at 87.24 percent of the ballot pool, and the initial ballot for the associated Implementation Plan received 75.89 percent approval with 88.15 percent quorum. The non-binding poll for the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") received 69.1 percent supportive opinions, reaching quorum at 85.61 percent of the ballot pool.[6] There were 67 sets of responses, including comments from approximately 152 different individuals and approximately 98 companies, representing all 10 industry segments.[7]

C. Second Posting - Comment Period, Additional Ballot, and Non-binding Poll – Phase I

Proposed Reliability Standard PRC-002-4, the associated Implementation Plan and other associated documents were posted for a 45-day formal comment period (that was extended to 46 days) from September 26, 2022 through November 10, 2022, with a parallel additional ballot and non-binding poll held from October 31, 2022 through November 14, 2022.[8] The additional ballot for the proposed Reliability Standard PRC-002-4 received 96.36 percent approval, reaching quorum at 75.52 percent of the ballot pool.[9] The additional ballot for the Implementation Plan received 95.85 percent approval, reaching quorum at 75.96 percent of the ballot pool.[10] The non-binding poll for the associated VRFs and VSLs received 96.09 percent supportive opinions, reaching quorum at 78.42 percent of the ballot pool.[11] There were 46 sets of responses, including

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6 *See* Exhibit F, Complete Record of Development, at items 27, 29.
7 *Id.* at items 24, 25.
8 The additional ballot was extended to reach quorum. *Id.* at items 40, 43, 44.
9 *Id*. at item 45.
10 *Id*. at item 46.
11 *Id*. at item 47.

comments from approximately 89 different individuals and approximately 63 companies, representing 8 industry segments.[12]

D. Final Ballot – Phase I

Proposed Reliability Standard PRC-002-4 was posted for a 10-day final ballot period from December 7, 2022 through December 16, 2022.[13] The final ballot for proposed Reliability Standard PRC-002-4 reached quorum at 83.79 percent of the ballot pool, receiving support from 96.43 percent of the voters.[14] The ballot for the Implementation Plan reached quorum at 84.32 percent of the ballot pool, receiving support from 96.11 percent of the voters.[15]

E. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standard PRC-002-4 on February, 16 2023.[16]

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12 *Id.* at items 41, 42.

13 *Id.* at item 56.

14 *Id*. at item 57.

15 *Id*. at item 58.

16 NERC, *Board of Trustees Open Meeting Agenda Package February 16, 2023*, Agenda Item 8. (Project 2021-4 Modifications to PRC-002), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_Agenda_Package_February_16_2023.pdf.

Complete Record of Development

Project 2021-04 Modifications to PRC-002 - Phase II

Related Files

Status

Final ballots concluded at **8 p.m. Eastern, Friday, December 16, 2022** for the following standard and implementation plan:

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements
- Implementation Plan

Background

This project will be completed in two phases. The first phase addressed the scope regarding notifications relative to the sequence of events recording (SER) and fault recording (FR) data, and to clearly identify the BES Element owners that need to have SER and FR data for transformers and transmission lines with the associated identified bus in the Glencoe Light and Power SAR.

The second phase will address gaps the Inverter-Based Resource Performance Task Force (IRPTF) identified within the PRC-002. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.

Standard(s) Affected – PRC-002-3 Disturbance Monitoring and Reporting Requirements

Purpose/Industry Need

The purpose of PRC-002 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where SER and FR data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES).

With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices and periodic assessments, the location requirements and associated periodic assessments need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.

Subscribe to this project's observer mailing list

Select "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2021-04 Modifications to PRC-002" in the Description Box.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **PRC-002-4** **(48)** Clean | **(49)** Redline to Last Posted | **(50)** Redline to Last Approved **(This posting only addresses Glencoe Light SAR)** **Implementation Plan** **(51)** Clean| **(52)** Redline to Last Posted **Supporting Materials** **(53)** VRF/VSL Justification **Technical Rationale** **(54)** Clean | **(55)** Redline to Last Posted	**Final Ballot** **(56)** Info Vote	12/07/22 – 12/16/22	Ballot Results **(57)** PRC-002-4 **(58)** Implementation Plan	

Draft 2 **PRC-002-4** **(30)** Clean | **(31)** Redline to Last Posted | **(32)** Redline to Last Approved **(This posting only addresses Glencoe Light SAR)** **Implementation Plan** **(33)** Clean | **(34)** Redline to Last Posted **Supporting Materials** **(35)** Unofficial Comment Form – Glencoe Light (Word) **VRF/VSL Justification** **(36)** Clean | **(37)** Redline to Last Posted **Technical Rationale** **(38)** Clean | **(39)** Redline to Last Posted	Additioal Ballots and Non-binding Polls **(43)** Updated Info(Ballot Reminder) **(44)** Info Vote	10/31/22 - 11/14/22 (extended to reach quorum)	Ballot Results **(45)** PRC-002-4 **(46)** Implementation Plan **(47)** Non-binding Poll Results	
	Comment Period **(40)** Info Submit Comments	09/26/22 – 11/10/22 (extended)	**(41)** Comment Received	**(42)** Consideration of Comments
Draft 1 **PRC-002-4** **(17)** Clean | **(18)** Redline **(This posting only addresses Glencoe Light SAR)** **(19)** Implementation Plan **Supporting Materials** **(20)** Unofficial Comment Form – Glencoe Light (Word) **(21)** VRF/VSL Justification **(22)** Technical Rationale	Initial Ballots and Non-binding Polls **(26)** Info Vote	07/15/22 – 07/25/22	Ballot Results **(27)** PRC-002-4 **(28)** Implementation Plan Non-Binding Poll Results **(29)** PRC-002-4	
	Join Ballot Pools	06/09/22 – 07/08/22		
	Comment Period **(23)** Info Submit Comments	06/09/22 – 07/25/22	**(24)**Comments Received	**(25)** Consideration of Comments
SAR Glencoe Light **(13)** Clean | **(14)** Redline **SAR IRPTF** **(15)** Clean | **(16)** Redline	The Standards Committee accepted these SARs on January 19, 2022.			
Drafting Team Nominations Supporting Materials **(11)** Unofficial Nomination Form (Word)	Nomination Period **(12)** Info(Updated) Submit Nominations	06/14/21 – 07/30/21 (Extended)		
SAR Glencoe Light (1) (Formal) **SAR IRPTF (2)** (Informal) **Supporting Materials** **(3)** Unofficial Comment Form - Glencoe Light (Word) **(4)** Unofficial Comment Form - IRPTF (Word) **(5)** IRPTF Review of NERC Reliability Standards White Paper	Comment Period **(6)** Info (Updated) Submit Comments	06/14/21 – 07/13/21	**(7)**Comments Received Glencoe Light **(8)** Comments Received IRPTF	**(9)** Consideration of Comments Glencoe Light **(10)** Consideration of Comments IRPTF

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	April 8, 2021		
SAR Requester			
Name:	Terry Volkmann		
Organization:	Glencoe Light and Power NCR11444		
Telephone:	612-419-0672	Email:	terrylvolkmann@gmail.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The purpose of PRC-002-2[1] is to have adequate sequence of events recording (SER) and fault recording (FR) data available to facilitate analysis of Bulk Electric System[2] (BES) disturbances.			

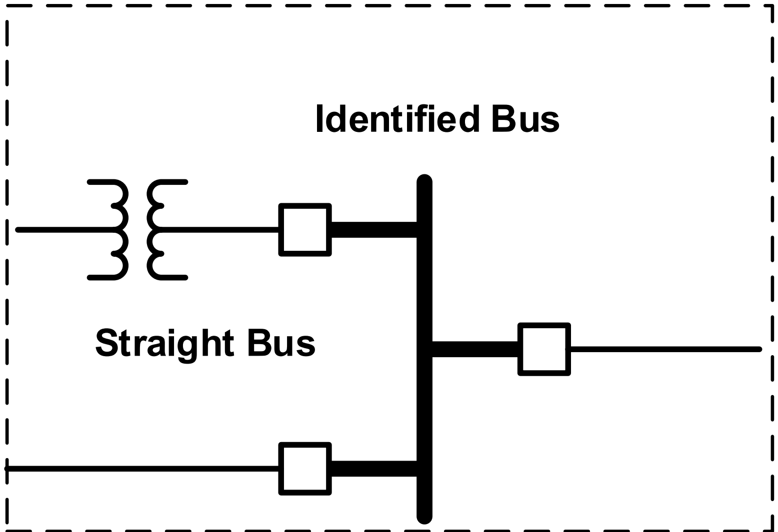
[1] NERC Reliability Standard PRC-002-2 Disturbance Monitoring and Reporting Requirements (https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&Jurisdiction=United%20States)
[2] See Glossary of Terms Used in NERC Reliability Standards (https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf)

Requested information
Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data and implicitly obligates these transformer or transmission line BES Element owners to either: 1. work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on for compliance, or 2. the transformer or transmission line BES Element owner must install its own equipment that is duplicative to the identified BES Bus recording equipment. Below is Requirement R1 for reference: **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. Notifications for FR data are being sent to BES Element owners that extend well beyond the BES bus boundary described in PRC-002-2 Attachment 1 as “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.” Notifying BES Element owners beyond this boundary unnecessarily obligates the BES Element (i.e., transformer or transmission line) owner to Requirement R3, including joint owners.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal of the proposed project is to clarify the necessary notifications in Requirement R1, Part 1.2 relative to FR data, and clearly identify the BES Element owners that need to have FR data for transformers and transmission lines with the associated identified bus.
Project Scope (Define the parameters of the proposed project):
The scope should include modifying Requirement R1, Part 1.2 to clarify notifications, which may include but is not limited to separating the SER data and/or FR data regarding notification. Additionally, Requirement R3 should be modified so that it is abundantly clear to the applicable Transmission Owner

Requested information
and Generator Owner when their BES Element must have FR data for an applicable transformer or transmission line.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[3] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The Transmission Owner (TO) applying the method in Attachment 1 who identifies a BES bus is in the ideal position to know which BES Elements (i.e., circuit breakers, transformer and transmission line) are connected to a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. Additionally, the identified BES bus owner should know who owns the particular BES Element (i.e., circuit breaker) that need FR data to capture disturbances on generators, transformers and transmission lines as identified in Requirement R3. Owners of BES Elements beyond the physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid should not be notified, unless their FR data is needed to complete the identified BES bus FR data. Requirement R1, Part 1.1 uses a method and BES bus definition[4] outlined in Attachment 1 to identify BES buses that require SER data and/or FR data. Part 1.2 requires the notification of other BES Element owners connected to the identified BES bus under Requirement R1, Part 1.1. As currently written, a notification is required regardless of whether the identified BES bus owner has FR data for the intended BES Element (i.e., transformer or transmission line) or owns the BES Elements directly connected to the identified BES bus. Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. This will eliminate unnecessary notifications and obligations transformer and transmission line owners to compel other entities to have FR data when there is no authority to do so. In these cases, the other BES Element owner(s) have to rely on FR data from another entity that does not have the obligation under the standard Additionally, clarifying the BES Element for which FR data is required will reduce auditing needs resulting from notifying BES Element owner who should not be responsible to have FR data as well as reducing the cost burden of meeting the reliability need for FR data.

[3] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[4] Attachment 1, 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.

Requested information
 The above figure of a straight bus is the simplest BES bus configuration contained within a common ground grid. Only the BES circuit breakers are connected to the identified BES bus. In this case it is clear concerning SER data in Requirement R2 because the circuit breaker is "directly connected." However, to achieve the need for FR data in Requirement R3, the identified BES bus owner notifies the transformer and transmission line owners under Requirement R, Part 1.2 thus obligating them to have FR data where the circuit breaker is directly connected and the logical BES Element to record FR data. Under the current Requirement R3, the notified GO or TO transformer or line owner will need to contact the circuit breaker owner in hope of obtaining FR Data or install their own equipment. The GO or TO cannot compel the circuit breaker owner to have FR data. Additionally, relying on another entity that has no reliability responsibility for complying with PRC-002-2 places the transformer or transmission line owner at risk if the other entity fails to have the necessary and adequate FR data. The intent of the standard in Requirement R3 is to have FR data associated with all applicable BES Elements at a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus. Requirement R1, Part 1.2 should only require notification to the BES Element (i.e., circuit breaker) owner directly connected with the identified BES bus. Having the appropriate BES Elements identified at the same voltage level within the same physical location sharing a common ground grid that require SER and/or FR data will help facilitate obtaining data by only having to seek the data from those entities directly connected to the identified BES bus. However, the current standard could be interpreted that generation, transformer and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus. As such, any modifications should consider alternative approaches that will achieve the intent of the standard while reducing associated cost and compliance burdens.

Requested information
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
None, the proposed modification above eliminates the unnecessary cost of being required to have FR data due to expanded notifications and the administrative burden to transformer and transmission line owners when these entities generally do not own the BES Elements that actually record the FR data.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owner and Generation Owner
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
A SAR was submitted by the NERC Inverter-based Resource Performance Task Force (IRPTF) to address potential gaps and improvements based on the work and findings of the IRPTF was authorized for posting by the NERC Standards Committee on January 20, 2021.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
Standard Implementation Guide or Practice Guide could provide the necessary clarity; however, these documents cannot change the strict language of the PRC-002-2 Reliability Standard. Nothing is being considered at the present time.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	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.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	

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SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC

	☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

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Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	June 10, 2020		
SAR Requester			
Name:	Allen Shriver, Chair Jeffery Billo, Vice Chair		
Organization:	Inverter-Based Resource Performance Task Force (IRPTF)		
Telephone:	Allen: 561-904-3234 Jeffery: 512-248-6334	Email:	Allen.Schriver@NextEraEnergy.com Jeff.Billo@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The “IRPTF Review of NERC Reliability Standards White Paper” was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed. The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR) data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES).			

Requested information
Requirements R1 and R5 are written with a focus on synchronous machine dominated systems with periodic review of monitoring equipment needs for the system. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. Inverter-based resources (IBRs) do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices. Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events. With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices and periodic assessments, the location requirements and associated periodic assessments need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise PRC-002-2 to address gaps within the existing standard. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS buses for which SER and FR data is required provides adequate monitoring of BES Disturbances. This may include updates to supplemental information such as the previously provided “Median Method Excel Workbook”. b. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS Elements for which DDR data is required provides adequate monitoring of BES disturbances. c. Consider other manners in which to add to, modify or clarify the existing requirements to ensure adequate monitoring of BES disturbances.

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data. However, BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring, though it is possible that monitoring in these areas is needed for disturbance analysis, as was the case in the Blue Cut Fire and Canyon 2 Fire events. Requirement R5, identifies BES locations based on a size criteria for generating resources and other critical elements such as HVDC, IROLs and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. In regard to generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. However, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR devices to ensure adequate coverage for disturbance analysis while balancing cost impacts.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The SAR proposes to modify PRC-002-2 requirements. The cost impact is unknown, however, the cost of disturbance monitoring hardware is approximately $50,000 to $100,000 per installation if the existing onsite equipment is not already set up for monitoring and storage.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
IBRs contribute very little short circuit MVA and are typically smaller in aggregate nameplate rating when compared to legacy synchronous resources. The criteria for selecting disturbance monitoring locations should take this into account.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinator, Reliability Coordinator, Generator Owner, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This issue was captured in the "IRPTF Review of NERC Reliability Standards White Paper" which was approved by the Operating Committee and the Planning Committee. Additionally, the IRPTF produced "BPS-Connected Inverter-Based Resource Performance"(see Chapter 6) and "Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources" reliability guidelines touch on monitoring considerations for IBRs.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
N/A
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The IRPTF did not identify any alternatives since there is a gap in PRC-002-2.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	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.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	N/A

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SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised

2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Unofficial Comment Form

Project 2021-04 Modifications to PRC-002-2

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-04 Modifications to PRC-002-2 Standard Authorization Request (SAR).** Comments must be submitted by **8 p.m. Eastern, Tuesday, July 13, 2021.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 404-446-9618.

Background Information

Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data and implicitly obligates these transformer or transmission line BES Element owners to either:

1. work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on for compliance, or
2. the transformer or transmission line BES Element owner must install its own equipment that is duplicative to the identified BES Bus recording equipment.

The goal of the proposed project is to clarify the necessary notifications in Requirement R1, Part 1.2 relative to FR data, and clearly identify the BES Element owners that need to have FR data for transformers and transmission lines with the associated identified bus.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. Provide any additional comments for the SAR drafting team to consider, if desired.

   Comments:

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Unofficial Comment Form

Project 2021-04 Modifications to PRC-002-2

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-04 Modifications to PRC-002-2 Standard Authorization Request (SAR).** Comments must be submitted by **8 p.m. Eastern, Tuesday, July 13, 2021.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 404-446-9618.

Background Information

The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The "IRPTF Review of NERC Reliability Standards White Paper" was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed.

The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR) data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES).

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. Provide any additional comments for the SAR drafting team to consider, if desired.

   Comments:

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IRPTF Review of NERC Reliability Standards

NERC Inverter-Based Resource Performance Task Force (IRPTF)
White Paper - March 2020

Executive Summary

The electric industry is still experiencing unprecedented growth in the use of inverters as part of the bulk power system and growth is possibly creating new circumstances where current standards may not be sufficiently addressing those needs. As a result, the NERC Planning Committee (PC) and Operating Committee (OC) assigned the task of evaluating today's current standards and requirements to the Inverter-Based Performance Task Force (IRPTF). This white paper details the findings of the IRPTF as a result of this activity and makes recommendations on actions that should be taken to address the issues identified.

Recommendations

The IRPTF identified potential gaps and areas for improvements in the following standards, and makes the following recommendations:

1. **FAC-001-3 and FAC-002-2** should be revised to: (a) clarify which entity is responsible for determining which facility changes are materially modifying, and therefore require study, (b) clarify that a Generator Owner should notify the affected entities before making a change that is considered materially modifying, and (c) revise the term "materially modifying" so as to not cause confusion between the FAC standards and the FERC interconnection process;

2. **MOD-026-1** and **MOD-027-1** should either be revised or a new model verification standard should be developed for inverter-based resources (IBRs) since these standards stipulate verification methods and practices which do not provide model verification for the majority of the parameters within an inverter-based resource. For example, the test currently used to comply with MOD-026-1 does not verify the model parameters associated with voltage control behavior during large disturbance conditions;

3. **PRC-002-2** should be revised to require disturbance monitoring equipment in areas not currently contemplated by the existing requirements, specifically in areas with potential inverter-based resource behavior monitoring benefits;

4. Clarifications should be made to **TPL-001-4** to address terminology throughout the standard that is unclear with regards to inverter-based resources the next time the standard is revised. This terminology was not changed in the recently FERC-approved **TPL-001-5** version of the standard; and

5. **VAR-002-4.1** should be revised to clarify that the reporting of a status change of a voltage controlling device per Requirement R3 is not applicable for an individual generating unit of a dispersed power producing resource, similar to the exemption for Requirement R4.

The IRPTF did not identify issues with the existing standard language in the BAL, CIP, COM, EOP, INT, IRO, NUC, PER, or TOP NERC Reliability Standards.

The IRPTF recommends that a Standards Authorization Request (SAR)s be developed to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, due to the continued growth of BPS-connected inverter-based resources.

Background

The IRPTF was formed in 2017 following several grid disturbances involving IBRs. In 2018, the PC and OC approved an IRPTF-developed white paper[1] on identified gaps in PRC-024-2 based on IRPTF's findings following investigations of the grid disturbances. Subsequently, a SAR to modify PRC-024-2 based on the white paper was endorsed by the PC and OC and approved by the NERC Standards Committee. This led to the formation of a Standards Drafting Team (SDT) to modify PRC-024-2.

In 2019, the IRPTF undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there are any further potential gaps or improvements beyond what was identified for PRC-024-2, based on the work and findings of the IRPTF. To accomplish this activity, IRPTF volunteers reviewed all of the current and future enforceable reliability standards, identified potential gaps or improvements, and presented findings to the entire IRPTF. The IRPTF reviewed these findings and finalized a set of recommendations.

The IRPTF acknowledges that the findings in this whitepaper are limited by the knowledge of its members and other issues may be discovered as industry and technology continues to evolve and grow. Any such issues may be addressed through the NERC technical committee or Standards Committee processes. In particular, the IRPTF acknowledges that it did not have subject matter experts in regards to the CIP, COM, NUC, and PER standards. Nevertheless, the IRPTF performed a cursory review of these standards and did not identify any potential gaps or improvements related to IBRs.

A similar review was also conducted as part of NERC Project 2014-01 for dispersed power producing resources.[2] However, industry knowledge of IBR technology and experience with NERC Reliability Standards implementation has evolved since that project was completed. For example, the Project 2014-01 efforts led to revisions of PRC-024-1, but those efforts did not capture the issues IRPTF identified in the PRC-024-2 Gaps Whitepaper.

FAC Standards Issues

The IRPTF identified issues with FAC-001-3 and FAC-002-2 that should be addressed. The IRPTF did not identify any issues with any other FAC standards.

FAC-001-3 and FAC-002-2

[1] PRC-024-2 Gaps White Paper, https://www.nerc.com/pa/Stand/Project%20201804%20Modifications%20to%20PRC0242/NERC%20IRPTF%20PRC-024-2%20Gaps%20Whitepaper.pdf

[2] Project 2014-01 Whitepaper, https://www.nerc.com/pa/Stand/Prjct201401StdrdsAppDispGenRes/DGR_White_Paper_v17_clean_01_13_2016_Final_rev1.pdf

The purpose of FAC-001-3 is to ensure that Facility interconnection requirements exist for Transmission Owners and Generator Owners (GO)s when connecting new or materially modified facilities. The purpose of FAC-002-2 is to ensure studies are performed to analyze the impact of interconnecting new or materially modified facilities on the Bulk Electric System (BES). An ambiguity exists in these standards for both synchronous resources and IBRs, but it may be amplified for IBRs that are comprised of many smaller individual units connected through a network of collection feeder circuits.

Both standards imply that the term “materially modified” should be used to distinguish between facility changes that are required to be studied and those that need not be studied. However, there is not a requirement for any entity to determine what changes are to be considered materially modifying and GOs are not required to notify potentially affected entities of the changes. This has led to confusion and potential reliability issues within industry. For example, a Transmission Planner (TP) may consider an IBR control system software change to be materially modifying, but if the GO does not consider such a change to be materially modifying they will not notify the TP of the change.

Additionally, the frequency of change of components could be higher for IBRs and the magnitude of such changes could vary. For example, due to a rapid change in wind turbine generator (WTG) technology, it is a common practice to re-power an existing wind power plant with bigger blades while keeping the same electrical generator and converter systems (for both Type 3 and Type 4 WTGs). This may be considered a material modification since a new set of bigger blades (e.g., 93 m to 208 m) can produce more power at a lower wind speed. However, the nameplate rating of the plant will remain unchanged. From an interconnection requirements’ perspective, it is the electrical generator and converter system that impacts the majority of the steady-state, short-circuit, and dynamic characteristics and therefore will be mostly unchanged. Therefore, the question remains if these sort of repowering projects should be studied under FAC-002-2 R1 and which entity should make that determination. Therefore, the IRPTF recommends these standards be modified to specify which entity is responsible for determining what facility changes should be considered materially modifying and requiring that Generator Owners notify the appropriate affected entities before they make such a change.

The IRPTF further notes that if the plant owner makes a change in electrical generator, power electronic converter, or any control systems (including change of OEMs for partial individual units), it should be considered as “materially modifying”. On the other hand, due to the advanced nature of control systems in the power electronic converters, it is not uncommon to have firmware updates (similar to the updates on a personal computer) occasionally that may have no impact on the functionalities of the WTGs or plant-level controls in any way. Therefore, such firmware updates that do not affect the electrical performance of the plant should not be considered as “materially modifying”.

Additionally, in FERC-jurisdictional areas, the term “Materially Modification” refers to a new generation project’s impact on other generators in the interconnection queue. This has led to widespread confusion across the industry regarding the correct application of these terms related to the FERC Open Access Transmission Tariff (OATT) implementation and the NERC Reliability Standards requirements. The application of these terms is different between the FERC process and the NERC Reliability Standards (specifically FAC-001-3 and FAC-002-2). For example, if a GO changes out the inverters on an existing solar

PV resource, the change may have no impact on other generators in the interconnection queue, and thus would not be considered a material modification under the FERC OATT rules. But such a change could have reliability impacts on the system that should be studied in accordance with FAC-002-2. Any revision to these standards should consider changing the term to avoid this confusion. FAC-001-3 and FAC-002-2 should be modified to clarify the use of “materially modifying”, particularly as it relates to compliance with the standards.

MOD Standards Issues

The IRPTF identified issues with MOD-026-1 and MOD-027-1 that should be addressed. The IRPTF did not identify any issues with any other MOD standards that are not already being addressed in other forums.

MOD-026-1 and MOD-027-1

MOD-026-1 and MOD-027-1 require, among other things, GOs to provide verified dynamic models to their TP for the purposes of power system planning studies. Both standards contain language that is specific to synchronous generators and is not applicable to IBRs. For example, sub-requirement 2.1.3 in MOD-026-1 states that each verification shall include “model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia” The standards should be revised to clarify the applicable requirements for synchronous generators and IBRs. For example, total rotational inertia should not be required for IBRs, while voltage ride-through control settings should only be required of IBRs and not synchronous generators.

To some degree, all dynamic model parameters affect the response of a represented resource in dynamic simulations performed by power engineers. Accurate model response is required for the engineers to adequately study system conditions. Hence, it is crucial that all parameters in a model be verified in some way. However, a significant number of parameters in the models are not verified in the typical verification tests used to comply with MOD-026-1 and MOD-027-1. For example, the test currently used to comply with MOD-026-1 does not verify the model parameters associated with voltage control behavior during large disturbance conditions.

This issue is one of the predominant reasons why ride-through operation modes such as momentary cessation were able to persist and promulgate in IBRs without the knowledge of planners and system operators until the Blue Cut Fire and Canyon 2 Fire events exposed them. The dynamic models did not accurately represent this large disturbance behavior due to the model deficiency and because certain key parameters that govern large disturbance response were incorrectly parameterized. However, many of the same plants that entered momentary cessation mode during these events were able to provide verification reports that demonstrated that the small disturbance behavior driven mainly by plant-level control settings reasonably matched modeled performance in compliance with these standards.

This reliability gap exists for both synchronous generators and IBRs. However, it is potentially more severe for IBRs since their behavior is based more on programmable control functions than for synchronous generators which have behavior that is based more on the physical characteristics of the machine. Both MOD-026-1 and MOD-027-1 should be reviewed and potentially revised to provide sufficient clarification for verification of generating resource model parameters, or a new standard should be developed to meet the reliability objective. Additionally, the IRPTF notes that it is not feasible to stage large disturbances for verification purposes, so other methods for verification of model performance under large disturbance conditions may need to be developed.

PRC Standards Issues

The IRPTF identified issues with PRC-002-2 that should be addressed. The IRPTF did not identify any issues with any other PRC standards that are not already being addressed in other forums.

PRC-002-2

The purpose of the NERC standard PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 provide guidance on selecting BES elements where data monitoring is required, which is summarized briefly below.

1. Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data.
2. Requirement R5, identifies BES locations based on a size criteria for generating resources and other critical elements such as HVDC, IROLs and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. In regard to generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA.

Requirements R1 and R5 are written with a focus on synchronous machine dominated systems. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices, respectively.

Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events.

With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices, the location requirements need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.

TPL Standards Issues

The IRPTF did not identify any requirements that may need to be changed in TPL-007-3, Transmission System Performance for Geomagnetic Disturbance Events, or the upcoming revisions to the standard. The IRPTF did identify several clarifications that may be helpful in the requirements of TPL-001-4, Transmission System Planning Performance Requirements. However, these clarifications are minor in nature and do not warrant changing the standard at this time. These clarifications should be considered by a subsequent SDT if the standard is revised in the future.

TPL-001-4

TPL-001-4 requires Planning Coordinators (PCs) and TPs to assess the reliability of their portion of the BES for various conditions across several specified future years and to plan Corrective Action Plans to address identified performance deficiencies. The requirements and sub-requirements include, among other things, certain simulation assumptions to be used by the planner and performance requirements.

Sub-requirements 3.3 and 4.3 describe simulation assumptions that the planner should use when performing contingency analysis for the steady-state and stability portion of the assessment, respectively. Sub-requirements 3.3.1.1 and 4.3.1.2 each require the planner to include the impact of the "tripping of generators where simulations show generator bus voltages or high side of the [GSU] voltages are less than known or assumed generator" low voltage ride-through capability.

The term GSU transformer can be confusing to GOs of IBR facilities because they will often refer to the transformer that steps the voltage up from the individual inverter (e.g., 600 V) to the collector system voltage (e.g., 34.5 kV). In this case, there is usually another transformer (i.e., the MPT) to step the voltage up from the collector system voltage to transmission system voltage. It was likely the intent of the TPL-001-2 SDT to be referring to transmission system voltages when drafting the language that refers to known or assumed generator low voltage ride-through capability at the high-side of the GSU. Therefore, the language in these sub-requirements should be modified to provide clarity for inverter-based resources.

Sub-requirements 4.1.1 and 4.1.2 provide stability performance criteria when a generator "pulls out of synchronism" in system simulations. Although an inverter-based resource does synchronize with the grid, the phrase "pulls out of synchronism" is typically applicable only to synchronous generators, referring to when a synchronous machine has an angular separation from the rest of the grid. Therefore, these sub-requirements could be clarified by clearly stating that this performance criteria is for synchronous generators.

Sub-requirement 4.3.2 specifies that stability studies must "simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area." It then contains a list of example devices that have dynamic behavior. Not included in this list are power plant controllers and inverter controls, which often dominate the dynamic response of IBRs. While the sub-requirement does not preclude the simulation of plant-level controllers and inverter controls, it would add clarity if they were added to the list.

The suggested clarifications for sub-requirements 3.3, 4.3, 4.1.1, 4.1.2, and 4.3.2 should be considered by a future SDT when editing the standard. However, the IRPTF does not believe the clarifications by themselves warrant changing the standard at this time. It should be noted that the identified issues with TPL-001-4 also apply to the draft TPL-001-5 standard that is awaiting FERC approval as of the publication of this whitepaper.

VAR Standards Issues

The IRPTF identified issues with VAR-002-4.1 that should be addressed. The IRPTF did not identify any issues with any other VAR standards.

VAR-002-4.1

The purpose of VAR-002-4.1 is "to ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection." Requirement R3 requires each Generator Operator (GOP) to notify its Transmission Operator (TOP) of a status change on "the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change." Requirement R4 is similar in that it requires each GOP to notify its TOP of "a change in reactive capability due to factors other than a status change described in Requirement R3."

For dispersed power producing resources, it is not clear if a GOP is required to notify the TOP for the status change of voltage control on an individual generating unit. For example, if an IBR consisting of one hundred inverters has one inverter trip out of service, is the GOP required to notify the TOP per Requirement R3? NERC Project 2014-01 revised VAR-002 Requirement R4 to clarify that it is not applicable to individual generating units of dispersed power producing resources. The IRPTF did not identify any reason why Requirement R3 should be treated differently than Requirement R4 in this respect and recommends VAR-002-4.1 be modified to make this same clarification to Requirement R3.

Conclusion and Recommendation

The IRPTF performed a comprehensive review of NERC Reliability Standards to determine if there were potential gaps for improvements based on the work and findings of the IRPTF. The outcome of this analysis includes the following recommendations:

1. **FAC-001-3 and FAC-002-2** should be revised to address the issues described herein;
2. **MOD-026-1** and **MOD-027-1** should either be revised to address the issues described herein or a new model verification standard should be developed for IBRs
3. **PRC-002-2** should be revised to address the issues described herein;
4. Clarifications should be made to **TPL-001-4** to address the issues described herein the next time the standard is revised. This recommendation also applies to the draft **TPL-001-5**; and
5. **VAR-002-4.1** should be revised to address the issues described herein.

The IRPTF recommends that a SAR(s) be developed to address each of the issues identified. IRPTF recommends that this be made a priority by the NERC Standards Committee, due to the continued growth of BPS-connected inverter-based resources.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

UPDATED

Standards Announcement

Project 2021-04 Modifications to PRC-002-2 Standard Authorization Requests

Comment Periods Open through July 13, 2021

Now Available

A 30-day formal comment period for Glencoe Light SAR and a 30-day informal comment period for the IRPTF SAR for **Project 2021-04 Modifications to PRC-002-2** Standard Authorization Requests (SARs), are open through **8 p.m. Eastern, Tuesday, July 13, 2021.**

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email), or at 404-446-9618. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-04 Modifications to PRC-002-2” in the Description Box.

RELIABILITY CORPORATION

North American Electric Reliability Corporation
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name: 2021-04 Modifications to PRC-002-2 | Glencoe Light SAR

Comment Period Start Date: 6/14/2021

Comment Period End Date: 7/13/2021

Associated Ballots:

There were 23 sets of responses, including comments from approximately 56 different people from approximately 50 companies representing 7 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

2. Provide any additional comments for the SAR drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Susan Sosbe	Wabash Valley Power Association	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	4	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Jodi Jensen	Western Area Power Administration - Upper Great Plains East (WAPA)	1,6	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO

					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1,3,5	MRO
					Joe DePoorter	Madison Gas and Electric	4	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					Bill Shultz	Southern Company Generation	5	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF

					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy- FirstEnergy	4	RF

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	No
Document Name	
Comment	
We believe that the notified interconnecting entity should have the FR/SER coverage on the notified BES Element(s) jointly owned by the interconnecting entities, which connect to the applicable bus owned by the notifying entity. We do not agree that the requirement calls for FR/SER monitoring on the lines, buses, transformers, and breakers on the bus owned by the notified entity, if the interconnecting BES element is only the line connecting to the bus owned by the notifying entity, as stipulated in the SAR proposal.	
Likes 0	
Dislikes 0	
Response	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The existing language of the standard defines only that the individual entities must provide notification and have data available. Under this language the entities are still free to collaborate in providing SER and FR data. The full submission from Glencoe Light and Power Goes on to stipulate: Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. Following this more prescriptive language recommended by Glencoe limits the opportunity for collaboration.	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Black Hills Corporation would also recommend including more clarification on which party (BES bus owner or BES element owner) is responsible for installing FR and/or SER equipment.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 3,5,6

Answer	Yes
Document Name	

Comment

AEP agrees with the proposed scope, direction, and intended purpose and goals of the proposed SAR as drafted by Glencoe Light and Power. We recommend it be pursued, as we believe the effort would provide clarity and that the resulting efficiencies would benefit industry.

While both the IRPTF SAR and the Glencoe Power and Light SAR each focus on revising PRC-002, their perceived needs and expressed goals are quite different. Because only one single SAR governs a project at any point in time, and because the unique efforts for the IRPTF SAR will likely be met with much more resistance than the Glencoe SAR, AEP recommends breaking this project into multiple phases, each with its own SAR governance. The Glencoe SAR will likely encounter less resistance from industry than the IRPTF SAR, so we recommend that the Glencoe SAR govern the first phase of the project. Once that phase is complete, the second phase could then begin with the IRPTF SAR governing Phase 2. Pursuing Project 2021-04 this way would be much more efficient, allowing progress to be made more quickly on the purpose and goal on the Glencoe SAR, and without potential delay associated to any resistance to efforts related to the IRPTF SAR.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The notification and data responsibility requirements in PRC-002 R1 and R3 needs clarification.

When identifying BES buses for monitoring bus in this standard is defined as a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid. For the sake of this standard, the BES Elements identified for monitoring should be defined in the same way avoiding including BES Elements that are remote to the identified BES bus-like transmission lines and their remote terminals.

The original intent of the standard drafting team was to make sure that the SER and FR data was available at the identified buses, so the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers.

Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
N/A.	
Likes 0	
Dislikes 0	

Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS supports the scope of the SAR submitted by Glencoe Light.	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
As noted by SAR written by Glencoe Light, the existing standard needs to be clarified as to whether it applies to directly connected versus remote buses indirectly connected. Pages 3 & 4 of the Glencoe Light SAR describe cases where ownership, notification, and compliance applicability for SER and/or FR data need to be clarified.	
Likes 0	
Dislikes 0	
Response	
William Steiner - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
MRO agrees with the SAR that, in situations where the identified BES bus owner has the capability to measure and record the required FR data, the notification required by R1.2 and the possession of data required by R3 create compliance burdens for the entities subject to those requirements but may not be the best way to ensure that the data will be available for analysis. However, the solutions proposed in the SAR do not appear to ensure that the obligation to have data will be assigned clearly to one equipment owner. The SAR suggests that the owner of a BES Element connected to an identified BES bus should only be made responsible for having FR data in situations where the owner of the identified BES bus lacks the capability to obtain the data. This, however, would constitute a sort of cascading applicability scheme where the failure of one entity (the bus owner) to meet the	

data requirement would kick the obligation back to the connected BES Element owner. This approach seems difficult to enforce and does not fully mitigate the issue of uncooperative neighboring entities.

While not fully supportive of the proposed solutions in the SAR, MRO does support revision of the standard to mitigate the dependency of one equipment owner on another to meet the data possession requirement in R3. Other applicability schemes could likely be utilized to make the applicability of each requirement clear to all entities.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1,5

Answer	Yes
Document Name	

Comment

Reclamation recommends the owner of the required equipment be the evaluating entity. Criteria to determine what Facilities require SER/FR and DDR equipment should be provided to remove ambiguity. Reclamation recommends the scope of the SAR also include the items described in the response to Question 2.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Evergy supports and incorporates by reference Edison Electric Institute’s (EEI) response to Question 1.

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	Yes
Document Name	

Comment	
In general Capital Power (on behalf of Decatur Energy Center and other Group 80 MRRE assets) agrees with the proposed scope. Please see additional comments in response 2.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the concern identified in the Glencoe Light SAR that Requirement R1, Subpart 1.2 does not clearly identify under what conditions notified owners of BES Elements connected to BES busses, identified under Part 1.2 of PRC-002-2; are obligated to install sequence of events recording (SER) and fault recording (FR) equipment. Additionally, given the parallel posting of both the IRPTF and Glencoe Light SARs, consideration should be given to addressing these two SAR under a single project but through a multi-phased approach with the Glencoe Light scope SAR being addressed in the first phase.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA supports the project scope to modify Requirement R1, Part 1.2 to clarify notifications – it's been unclear both what to expect in return when we send out a notification as well as what to do with a notification when we receive one. Because of this, we have done SER and DFR reviews on stations that were identified to us by other entities on top of completing reviews of our PRC-002-2 identified stations. More clarity is needed on what specifically must happen when you receive a notification. The standard also states that the owner must supply the data upon request, but BPA has worked with other utilities to ensure we don't have gaps. There needs to be some leeway on allowing two or more utilities to have a formal, pre-established agreement if they choose to do so. It helps save utilities on cost if they can.	
Likes 0	
Dislikes 0	

Response

2. Provide any additional comments for the SAR drafting team to consider, if desired.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

While Texas RE generally supports the scope of the proposed SAR and the overall intent of the proposed project, Texas RE proposes two additional areas for consideration in the upcoming project to improve the proposed PRC-002 Standard's overall effectiveness. First, the SDT should move periodic requirements set forth in the PRC-002 Implementation Plan directly in the Standard Requirement language contained in PRC-002-2 R1.3. Second, the SDT should review the "Median Method Excel Workbook" for potential anomalies. Texas RE provides additional details on each of these items below.

Periodic Requirements in the PRC-002-2 Implementation Plan

Texas RE is concerned there is a periodic requirement in the Implementation Plan for PRC-002-2, rather than in the requirement itself. Consistent with Standard Processes Manual, Section 4.4.3, implementation plans are intended to describe the proposed effective date, identify new or modified definitions, specify any prerequisite actions that need to be accomplished before entities are held responsible for compliance with the requirements, describe whether any conforming changes to other Reliability Standards will occur, and finally the Functional Entities that will be required to comply with the requirements.

In contrast to these core implementation plan elements, the PRC-002-2 implementation plan sets forth an explicit compliance periodicity that is not solely associated with registered entities' transition to compliance with the PRC-002-2 requirements. In particular, PRC-002-2, R1.3 states that TOs shall "re-evaluate buses at least once every five years and notify other owners…***and implement the re-evaluated list of BES buses as per the Implementation Plan.***" The current PRC-002-2 implementation plan in turn provides that "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 that list." When read together, therefore, the PRC-002-2 Registered Entities must continue to reference the current PRC-002-2 implementation plan in order to understand the requirement to implement the re-evaluated list of BES buses on a three-year cycle.

Texas RE recommends moving the three-year requirement from the PRC-002-2 implementation plan to the requirement language itself, as it is essentially a periodic requirement for TOs and is no longer associated with the prerequisite actions that need to be accomplished before Registered Entities are held responsible for PRC-002-2 R1.3. Such a change will provide additional clarity to registered entities as well as reduce the number of extraneous documents needed to comply with the standard.

Workbook Anomalies

In addition to explicitly incorporating the three-year BES bus re-evaluation language directly into the PRC-002-2 R1.3 requirement language, Texas RE also recommends the drafting team conduct a general re-evaluation of the "Median Method Excel Workbook" (located on the original project page) to ensure accurate evaluations. During the course of its ongoing compliance engagements, Texas RE staff discovered several potential anomalies and possible incorrect calculations throughout the Workbook. For example, Texas RE noticed the use of "SOER" (Sequence of Events Recording) within the Workbook, which had been removed from a Rationale dialog box in a May 2014 redline:

(https://www.nerc.com/pa/Stand/Project%20200711%20Disturbance%20Monitoring%20DL/PRC-002-2_Disturbance_Monitoring_2014May09_redline.pdf).

Texas RE staff also determined the same number of bus placements based on the example data but that number **differed** from the example provided within the Workbook. When using real world data, it was discovered that there may not be enough guidance to determine bus placement in a repeatable fashion as Workbook instructions appeared to not consider repeat values for three phase short circuit (e.g. multiple busses having the same short circuit values).

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI looks forward to reviewing a future Project 2021-04 SAR, which contains elements of both SARs.

Likes 0	
Dislikes 0	

Response

Shannon Ferdinand - Decatur Energy Center LLC - 5

Answer	
Document Name	

Comment

Capital Power (on behalf of Decatur Energy Center and other Group 80 MRRE assets) appreciates any opportunity to reduce the administrative burden related to certain Reliability Standards. However, in this case, the notification of only the impacted entities may result in instances where, due to an administrative error, a potentially in-scope entity is not notified and assumes it is out of scope because no notification was received. To mitigate this risk, Capital Power recommends one of the following solutions:

- Comprehensive, easily accessible list of all in-scope buses as well as what data is required
    - This will allow all entities, including those who may not have received a direct notification, to ensure that the lack of notification was not due to an administrative error
    - Ideally this list should be stored and/or facilitated on/via a centralized system such as NERC's Align system.
- Positive confirmation of out of scope – TOs should notify all entities of their in-scope or out of scope status

- Develop selection criteria specific to generators (inclusive of synchronous and inverter-based resources). Based on these criteria generators would be accountable and have the mechanism to make their own determination re. which assets require SER and FR.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 2.

Likes 0	
Dislikes 0	

Response

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

In general PRC-002 is loosely written. BPA has submitted questions to WECC for clarification. R4.3 states "Trigger settings for at least the following: 4.3.1 Neutral (residual) over current. 4.3.2 Phase undervoltage or overcurrent"; this can be interpreted that the XFMR can have a phase undervoltage trigger even though R3 states: "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."

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1,5

Answer	
Document Name	

Comment

Reclamation recommends the PRC-002 SAR include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items:

- In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators.
- Requirement R1.3 should be modified to state the timeframe within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO).
- Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.
- Reclamation recommends adding the sharing of protection system data when requested by the entity performing the R1 evaluation.
- Requirement R12 should be modified to add a required time limit within which to notify the Regional Entity(ies) of a failure of the recording capability. Regional Entities need to know as soon as the failure occurs or is discovered, not up to 90 days later.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

William Steiner - Midwest Reliability Organization - 10

Answer	
Document Name	

Comment

- MRO has noted that the standard is complicated and difficult to interpret. Proper interpretation requires a nuanced understanding of various terms including "BES bus", "BES Element", "connected", and "directly connected." These terms are defined by a combination of the NERC Glossary of Terms and the standard itself. The uses of these terms in the standard provide further insight into how the terms should be understood. A more straightforward approach to defining terms in the standard would likely help to clarify the locations where recording is required as well as the delineation of responsibilities for obtaining data.

- The SAR includes the statement "the current standard could be interpreted that generation, transformer and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus" and implies that this is somehow an unnecessary or undesirable interpretation. However, it is MRO's opinion that this is the proper interpretation as R3 does not dictate the exact location of current measurement, only that the entity must have current data for the applicable transmission lines and transformers. If, for some reason, the only location where current sensing and recording equipment was installed was at the remote end of a transmission line or transformer, it would make sense to utilize that equipment rather than require installation of new equipment nearer to the identified BES bus.

- Clarifications regarding the current version of the standard and MRO's interpretation:

  - R1.2 notifications do not obligate entities to have data, only R3 does that. The notifications ensure that BES Element owners with R3 obligations are aware of those obligations. An overreaching notification from the identified BES bus owner to an adjacent owner of equipment that does not meet the criteria given in R3 would not create any compliance obligation for the adjacent owner.
  - R1.2 and R3 are consistent with each other in addressing BES Elements "connected to the BES buses identified in Requirement R1."

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

Proccess qustion, with two different SAR write-ups (IRPTF from June 2020 and Glencoe Light from April 2021) out for comment, would the Standards Committee assign one SDT to both of these SARs or would the SARs be combined into one SAR?

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	
Document Name	

Comment

The proposal by Glencoe light does not address following issues, which should be addressed by the Standards Drafting Team on Requirement R1.

- The Requirement R1.2 obligates the notifying entity to notify the interconnecting entity about the FR or SER monitoring requirement on the interconnecting BES element(s) within 90 days of the determination of the BES buses. But it does not say anything about the obligation of the notified interconnecting entity in terms of time limits on their response or confirmation about implementing the FR/SER monitoring. There is provision to notify interconnecting FR/ER monitoring for the interconnecting BES element(s), but thereafter standard leaves it open. There is no follow-up on actual implementation of the FR/SER monitoring. The requirement should set some time limit on the notified entity to confirm/ or resolve issues if any towards implementing the FR/SER requirement. It should also address issues, when the applicable buses list of the notified interconnecting entity does not include the bus to which the interconnecting BES element in question is connecting.
- In the requirement R5, the Reliability Coordinator (RC) notifies the entities about DDR requirement. The RC should provide more details with the notification. Currently the RC notification merely includes the requirement no in the columns. It does not include why or how the requirement number was applied. For example If a notification of DDR monitoring goes to an entity under R5.1.5 (UVLS) or 5.1.2 (Stability of System Operating limits), then the standard does not clarify RC responsibility to notify other participating entities. The RC notification does not provide the details. What about the FR/SER monitoring requirement on those interconnections between entities if the buses do not figure in the 20% applicable buses list of the concerned entities?). The standard should address this.
- The requirement R1.1 should address step 8 of the algorithm in attachment 1 of the standard. For example, step 8 does not necessarily include the case of growing inverter-based resource monitoring. It has been noticed that while applying step 1-step7, the applicable buses tend to concentrate in the high MVA zones and distributed monitoring across the network does not occur. The standard or the algorithm need to be tweaked to address this issue.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.	
Likes 0	
Dislikes 0	
Response	

“Comments received from Jamie Johnson – California ISO”
Question 1
☒ Yes

Comments: Any clarifications to the scope of NERC registered entities responsibilities promote clarity and add to reliability activities.

Question 2 (no additional comments)

“Comments received from Wayne Sipperly – NAGF”
Question 1
☒ **Yes**

Comments:
The NAGF agrees with the proposed scope to clarify the notification and data responsibility requirements in PRC-002 R1 and R3. The BES Elements identified for monitoring should be defined as “a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid” to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Where the intent is to ensure that the SER and FR data is available at the identified buses, the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers

Question 2 (additional comments)
Comments:
PRC-002 R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.

The NAGF notes that the existing PRC-002-2 Rational section regarding R3 states that an FR exception exists for “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”. This needs to be clarified with regard to PRC-002-2 Requirement 1. TOs should be required to send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

“Comments received from Pamela Hunter – Southern Company”
Question 1
☒ **Yes**

Comments:
The notification and data responsibility requirements in PRC-002 R1 and R3 needs clarification.

The BES Elements identified for monitoring should be defined as “a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid” to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Where the intent is to make sure that the SER and FR data is available at the identified buses, the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers.

Question 2 (additional comments)
Comments:
R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.

The usual order of precedence for NERC standards is that the Rationale section only explains the requirements and does not modify them. PRC-002-2 breaks this rule by treating SER and FR in a one-size-fits-both fashion in R1, then saying in the Rationale section that an FR exception exists for, '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.' It is awkward to have a letter from the TO saying that FR is required, and having to point-out to auditors that the Rationale section of PRC-002-2 overrules. PRC-002-3 should have TOs send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

"Comments received from Daniel Gacek – Exelon"
Question 1
☒ **Yes**

Comments: Exelon agrees that the BES element owner should be responsible for data required for PRC-002-2. The BES Elements identified for monitoring should be defined as "a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid" to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Question 2 (additional comments)
Comments:
Receiving notifications from a TO that data is not required for a BES Element is beneficial and such notifications should not be eliminated by changes to the standard.

Comment Report

Project Name:	2021-04 Modifications to PRC-002-2 | IRPTF SAR
Comment Period Start Date:	6/14/2021
Comment Period End Date:	7/13/2021
Associated Ballots:	

There were 23 sets of responses, including comments from approximately 50 different people from approximately 44 companies representing 7 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

2. Provide any additional comments for the SAR drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	4	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Jodi Jensen	Western Area Power Administration - Upper Great Plains East (WAPA)	1,6	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO

					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1,3,5	MRO
					Joe DePoorter	Madison Gas and Electric	4	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					Bill Shultz	Southern Company Generation	5	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS does not support the scope of the SAR submitted by the NERC Inverter-based Resource Performance Task Force (IRPTF) because is too broad and does not provide specific information on the changes to be addressed by the standard drafting team. Additionally, AZPS does not agree that the IRPTF White Paper provides sufficient justification for revising the standard. AZPS's experience has shown that any significant inverter based resources tie into large substations for which the MVA requirement would cover the need for monitoring.	
Likes 0	
Dislikes 0	
Response	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
The City of Tallahassee (TAL) believes that requiring additional monitoring equipment is not cost-effective given the minor contribution to the BES in terms of fault current. TAL is unsure how the data collected will provide a substantial gain to the BES.	
Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA disagrees with this project scope. PRC-002-2 Attachment 1, Step 8 already says "the additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data." It then provides recommendations for selecting additional bus locations. We do not only rely on PRC-002-2 to require disturbance monitoring and recording. We have our own requirements for when to install	

disturbance monitoring and recording and the TO should know their system well enough to know when and where they need to monitor. In order to completely eliminate the possibility of not having data available for event analysis, you'd have to require monitoring and recording at every substation which may or may not be possible. The SAR mentions the IBRs don't provide enough fault current, thus they can contribute to a fault. PRC-002 is for wide area faults and reconstructing them. This SAR may be better applied to PRC-023 or another protection standard. The owners need to update their own standards for SER/FR equipment or at least protective systems (most offer both limited SER/FR capability).	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	

AEP believes there may be benefit in pursuing this SAR, however we do not believe that the burden to install SER, FR, and DDR should be placed on the Transmission Owner. Rather, any such obligations to do so should be placed solely on the Generator Owner of those resources.

We believe Attachment One should be revised to make it absolutely clear that it governs Transmission assets only. Generation resources deserve their own distinct selection criteria for R1 and R3, one that is inclusive of both synchronous generation and inverter based generation. Generator Owners should be able to make their determination on which assets require FR and SER solely on the resource in question, and not based on analysis regarding how that asset is compared to others. One suggested method to consider would be establishing individual and aggregate thresholds for when SER and FR would need to be installed.

While both the IRPTF SAR and the Glencoe Power and Light SAR each focus on revising PRC-002, their perceived needs and expressed goals are quite different. Because only one single SAR governs a project at any point in time, and because the unique efforts for the IRPTF SAR will likely be met with much more resistance than the Glencoe SAR, AEP recommends breaking this project into multiple phases, each with its own SAR governance. The Glencoe SAR will likely encounter less resistance from industry than the IRPTF SAR, so we recommend that the Glencoe SAR govern the first phase of the project. Once that phase is complete, the second phase could then begin with the IRPTF SAR governing Phase 2. Pursuing Project 2021-04 this way would be much more efficient, allow progress to be made more quickly on the purpose and goal on the Glencoe SAR, and without potential delay associated to any resistance to efforts related to the IRPTF SAR.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

Step 8 in Attachment 1 for R1 already provides a means by which bus locations not captured in the highest 10% bus fault current calculations are selected for SER and FR data monitoring to achieve the 20% total. Locations with Inverter Based Resources can be added to the list of recommended locations.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	Yes
Document Name	

Comment

The rationale for R1 on page 22 explains in detail the data analysis efforts which have gone into developing a methodology for identifying optimum number of buses. The study established a strong correlation between the short circuit MVA level available at a bus and its relative size based on voltage level, no. of transmission lines and other BES elements connected have an impact on system reliability. 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. Though entities could cover the inverter-based resources under optional buses in Step 8 of the algorithm in attachment 1 of the standard.

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	Yes
Document Name	

Comment

The existing standard targets BES elements with short circuit MVA in the top 20% which could leave out inverter-based resources. Recent events involving inverter-based resources (IBR), such as the Blue Cut Fire and Canyon 2 Fire, have demonstrated the need to monitor some inverter-based resources. The Project 2021-04 SAR (the portion written by the IRPTF) addresses the need to monitor some IBRs.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1,5

Answer	Yes
Document Name	

Comment	
Reclamation agrees with the addition of a requirement to further enhance SER/FR and DDR equipment in facilities on the premise that the information obtained not only enhances BES reliability but also enhances an entity's ability to troubleshoot and repair Facilities, further reduce operating costs, and increase reliability. Reclamation recommends the scope of the SAR also include the items described in the response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power (CP) (on behalf of Decatur Energy Center LLC and other MRRE group 80 assets) supports the NAGF submitted comments on this item.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI supports the concerns identified in the IRPTF SAR that current processes contained within PRC-002-2 (Attachment 1) used to identify BES buses where sequence of event (SER) and fault recording (FR) equipment are to be installed generally do not require the placement of this equipment on buses where IBR resources are prevalent. The SAR SDT should consider the potential fault recording differences that may be required by IBRs, such as the possible need for faster sampling rates for IBRs, while providing little value for synchronous resources. EEI also suggests SER and FR equipment might be efficiently placed at the point of aggregation where this information would be more useful. Additionally, given the parallel posting of both the IRPTF and Glencoe Light SARs, consideration should be given to addressing these two SAR under a single project but through a multi-phased approach with the Glencoe Light scope SAR being addressed in the first phase.	
Likes 0	
Dislikes 0	
Response	

2. Provide any additional comments for the SAR drafting team to consider, if desired.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI looks forward to reviewing a future Project 2021-04 SAR, which contains elements of both SARs.	
Likes 0	
Dislikes 0	
Response	

Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	

Capital Power (CP) (on behalf of Decatur Energy Center LLC and other MRRE group 80 assets) supports the NAGF submitted comments on this item.

In addition, CP supports Reclamation's recommendation of the following (modified slightly):

PRC-002 SAR should include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items:

- In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators.
- Requirement R1.3 should be modified to state the timeframe / implementation period within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO).
    - This is particularly important when it comes to newly identified BES buses in remote areas where DDR equipment may not already be on-site and will need to be designed, procured, and installed.
- Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.
- The addition of a requirement allowing exemption based on equipment limitation, age of asset etc. If a newly identified BES Bus happens to be connected to an existing asset nearing the end of its useful life, the cost / benefit of the installation of additional DDR equipment should be considered.

Likes 0	
Dislikes 0	
Response	

Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
In general, PRC-002 is loosely written. BPA has submitted questions to WECC for clarification. R4.3 states "Trigger settings for at least the following: 4.3.1 Neutral (residual) over current. 4.3.2 Phase undervoltage or overcurrent"; this can be interpreted that the XFMR can have a phase undervoltage trigger even though R3 states: "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."	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	
Reclamation recommends the PRC-002 SAR include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items: • In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators. • Requirement R1.3 should be modified to state the timeframe within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO).	

- Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.

- Reclamation recommends adding the sharing of protection system data when requested by the entity performing the R1 evaluation.

- Requirement R12 should be modified to add a required time limit within which to notify the Regional Entity(ies) of a failure of the recording capability. Regional Entities need to know as soon as the failure occurs or is discovered, not up to 90 days later.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	
Document Name	

Comment

The proposal from IRPTF does not address following issues, which the Standards Drafting Team (SDT) should consider.

- The requirement R1.1 should address step 8 of the algorithm in attachment 1 of the standard. For example, step 8 does not necessarily include the case of growing inverter-based resource monitoring. It has been noticed that while applying step 1-step7, the applicable buses tend to concentrate in the high MVA zones and distributed monitoring across the network does not occur. The standard or the algorithm need to be tweaked to address this issue.
- The algorithm could adopt the weighted points technique considering MVA, Voltage, NO. of lines, IROL (Interconnection Reliability Operating Limit) and SOL (Stability Operating Limit), UVLS schemes, and Vegetation parameters to derive a distributed FR/SER/DDR monitoring.
- Standard should address follow through action by notified entities participating in interconnection with the notifying entity in a time bound way to ensure adequate FR/SER/DDR monitoring in zones, where multiple entities are involved. DDR notification by Reliability Coordinators (RC) should have more details justifying the DDR requirement than merely quoting the requirement nos. in the notification document.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

Expand the scope to add an implementation period for newly identified BES buses. During five year reviews, new BES buses are identified, and particularly in the case of BES buses like ones that may be identified as a result of this SAR that are interconnected at remote areas of the system, DDR equipment may not already be on-site and will need to be designed, procured, and installed.

Likes 0	

Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy

Answer	
Document Name	

Comment

Duke Energy does not have comments at this time.

Likes 0	
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	
Document Name	

Comment

PRC-002-2 says in Requirement R1.2 that TOs shall, “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.” The expression “and/or” suggests that the two forms of DME might not be automatically conjoined; there could be cases in which need to install SER does not mean that FR is required also. This point is left hanging, though, in the PRC-002-2 Att. 1 methodology for selecting buses. The rules apply to, “SER and FR data,” together, not individually.

The issue is not clarified until one gets to the Rationale section of PRC-002-2, which confirms that there are SER-but-not-FR exceptions, “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.”

Talen Energy proposes that the FR exemption for GSUs and GSU-to-TO HV lines be stated in the Applicability section of PRC-002-3. The Rationale section of the standard should explain but not modify the Requirements section.

Likes 0	
Dislikes 0	

Response

“Comments received from Jamie Johnson – California ISO”
Question 1
☒ Yes

Question 2 (no additional comments)

“Comments received from Wayne Sipperly – NAGF”
Question 1
☒ **Yes**

Comments:
The NAGF supports the SAR project scope to ensure that sequence of events recording (SER), fault recording (FR) and dynamic Disturbance recording (DDR) devices are installed and periodically assessed for certain inverter-based resources (IBRs) thus providing adequate data to facilitate analysis of BES disturbances.

Question 2 (additional comments)
Comments:
Consider modifying the scope to add an implementation period for any newly identified BES buses. During five year reviews, new BES buses may be identified. DDR equipment may not already be on site and time is required for the design, procurement of material, and for installation.

The NAGF notes that the existing PRC-002-2 Rational section regarding R3 states that an FR exception exists for “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”. This needs to be clarified with regard to PRC-002-2 Requirement 1. TOs should be required to send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

“Comments received from Pamela Hunter – Southern Company”
Question 1
☒ **No**

Comments:
Changes to the standard are not necessary for IBR facilities. Step 8 in Attachment 1 for R1 already provides a means by which bus locations not captured in the highest 10% bus fault current calculations are selected for SER and FR data monitoring to achieve the 20% total. Locations with Inverter Based Resources can be added to the list of required locations at the Transmission Owner’s discretion.
.
Question 2 (additional comments)
Comments:
Modify the scope to add an implementation period for any newly identified BES buses. During five-year reviews, new BES buses may be identified. DDR equipment may not already be on site and time is required for the design, procurement of material, and for installation.

“Comments received from Daniel Gacek – Exelon”
Question 1
☒ No

Comments: While Exelon does not support the SAR in its current form, Exelon does support the concerns raised by the IRPTF regarding the need to place disturbance monitoring equipment (DME) closer to inverter-based resources (IBR). In addition to placing DME closer to IBRs, the specifications of the disturbance monitor equipment for IBRs will need to be developed to ensure data is sufficient to analyze system disturbances involving IBRs. The present PRC-002 methodology and disturbance monitoring equipment technical specifications, which is being implemented, serve conventional generation and buses remote from IBR well and those specifications should be preserved. Therefore, the SAR should be revised to specifically address the changes needed for IBR without altering the specifications for other resources.

Question 2 (additional comments)
Comments:
In the interest of system reliability and event analysis the responsible entities should be required to install DMEs in locations that would render the greatest amount of data for system analysis. For installations involving multiple IBRs that location may include an aggregation point such as the Point of Interconnection (POI) with the transmission system or transmission substation beyond the POI.

“Comments received from Brandon Gleason – ERCOT
☒ Yes

Comments: None

Question 2 (None)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2021-04 Modifications to PRC-002-2 | Glencoe Light SAR
Comment Period Start Date: 6/14/2021
Comment Period End Date: 7/13/2021
Associated Ballots:

There were 23 sets of responses, including comments from approximately 56 different people from approximately 50 companies representing 7 of the Industry Segments as shown in the table on the following pages.

All comments submitted can 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 of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

2. Provide any additional comments for the SAR drafting team to consider, if desired.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Susan Sosbe	Wabash Valley Power Association	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO

					Christopher Bills	City of Independence Power & Light	4	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Jodi Jensen	Western Area Power Administration - Upper Great Plains East (WAPA)	1,6	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO

					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1,3,5	MRO
					Joe DePoorter	Madison Gas and Electric	4	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					Bill Shultz	Southern Company Generation	5	MRO
Duke Energy		1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC

	Kim Thomas				Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	No
Document Name	
Comment	
We believe that the notified interconnecting entity should have the FR/SER coverage on the notified BES Element(s) jointly owned by the interconnecting entities, which connect to the applicable bus owned by the notifying entity. We do not agree that the requirement calls for FR/SER monitoring on the lines, buses, transformers, and breakers on the bus owned by the notified entity, if the interconnecting BES element is only the line connecting to the bus owned by the notifying entity, as stipulated in the SAR proposal.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This comment appears to agree with the intent of the SAR, so the "No" vote is confusing. One of the SAR DT members reached out to commenting entity to clarify the intent of this SAR. The revised SAR states that the standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. This should clarify requirements for the Responsible Entities.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

The existing language of the standard defines only that the individual entities must provide notification and have data available. Under this language the entities are still free to collaborate in providing SER and FR data. The full submission from Glencoe Light and Power Goes on to stipulate: Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. Following this more prescriptive language recommended by Glencoe limits the opportunity for collaboration.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. One of the SAR drafting member explained in the BHE cross-platform meeting why this SAR was necessary and that it would not limit collaboration, only clarify required data. Among other things, one of the goal of this SAR is to revise the standard so that requirements are clear and that it eliminates unnecessary and administrative compliance burden for the Responsible Entities.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation would also recommend including more clarification on which party (BES bus owner or BES element owner) is responsible for installing FR and/or SER equipment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification.	
Thomas Foltz - AEP - 3,5,6	

Answer	Yes
Document Name	
Comment	
AEP agrees with the proposed scope, direction, and intended purpose and goals of the proposed SAR as drafted by Glencoe Light and Power. We recommend it be pursued, as we believe the effort would provide clarity and that the resulting efficiencies would benefit industry. While both the IRPTF SAR and the Glencoe Power and Light SAR each focus on revising PRC-002, their perceived needs and expressed goals are quite different. Because only one single SAR governs a project at any point in time, and because the unique efforts for the IRPTF SAR will likely be met with much more resistance than the Glencoe SAR, AEP recommends breaking this project into multiple phases, each with its own SAR governance. The Glencoe SAR will likely encounter less resistance from industry than the IRPTF SAR, so we recommend that the Glencoe SAR govern the first phase of the project. Once that phase is complete, the second phase could then begin with the IRPTF SAR governing Phase 2. Pursuing Project 2021-04 this way would be much more efficient, allowing progress to be made more quickly on the purpose and goal on the Glencoe SAR, and without potential delay associated to any resistance to efforts related to the IRPTF SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. SAR DT recommends a multi-phased approach with Glencoe Light SAR being addressed first.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The notification and data responsibility requirements in PRC-002 R1 and R3 needs clarification.	

When identifying BES buses for monitoring bus in this standard is defined as a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid. For the sake of this standard, the BES Elements identified for monitoring should be defined in the same way avoiding including BES Elements that are remote to the identified BES bus-like transmission lines and their remote terminals. The original intent of the standard drafting team was to make sure that the SER and FR data was available at the identified buses, so the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification. The revised SAR states that the standard should clearly define the terms "directly connected" versus "connected" as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. Clarification using these terms should also address clarifying elements local to the identified BES bus versus remote breakers.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
No comments	
Likes 0	
Dislikes 0	
Response	

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
AZPS supports the scope of the SAR submitted by Glencoe Light.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
As noted by SAR written by Glencoe Light, the existing standard needs to be clarified as to whether it applies to directly connected versus remote buses indirectly connected. Pages 3 & 4 of the Glencoe Light SAR describe cases where ownership, notification, and compliance applicability for SER and/or FR data need to be clarified.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The revised SAR states that the standard should clearly define the terms "directly connected" versus "connected" as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements.	
William Steiner - Midwest Reliability Organization - 10	
Answer	Yes

Document Name	
Comment	
MRO agrees with the SAR that, in situations where the identified BES bus owner has the capability to measure and record the required FR data, the notification required by R1.2 and the possession of data required by R3 create compliance burdens for the entities subject to those requirements but may not be the best way to ensure that the data will be available for analysis. However, the solutions proposed in the SAR do not appear to ensure that the obligation to have data will be assigned clearly to one equipment owner. The SAR suggests that the owner of a BES Element connected to an identified BES bus should only be made responsible for having FR data in situations where the owner of the identified BES bus lacks the capability to obtain the data. This, however, would constitute a sort of cascading applicability scheme where the failure of one entity (the bus owner) to meet the data requirement would kick the obligation back to the connected BES Element owner. This approach seems difficult to enforce and does not fully mitigate the issue of uncooperative neighboring entities. While not fully supportive of the proposed solutions in the SAR, MRO does support revision of the standard to mitigate the dependency of one equipment owner on another to meet the data possession requirement in R3. Other applicability schemes could likely be utilized to make the applicability of each requirement clear to all entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Some examples are added in the revised SAR to illustrate why standard should be revised to clarify the intent of R1.2 and R3. Revisions made to standard clarifying responsibilities for each entity would ensure that adequate FR and SER data is available for analysis.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	

Reclamation recommends the owner of the required equipment be the evaluating entity. Criteria to determine what Facilities require SER/FR and DDR equipment should be provided to remove ambiguity. Reclamation recommends the scope of the SAR also include the items described in the response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The criteria to determine which facilities require SER/FR and DDR data/equipment is provided in Attachment 1 (referred in R1.1) and R5 respectively. The evaluating entity for SER/FR data/equipment is Transmission Owner, an entity responsible for short circuit model which is necessary to evaluate based on criteria in the Attachment 1. The evaluating entity for R5 is Responsible Entity as defined in 4.1., entity with all necessary data needed for evaluation. Also, please refer to response to Question 2.	
Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute’s (EEI) response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI's comment.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes

Document Name	
Comment	
In general Capital Power (on behalf of Decatur Energy Center and other Group 80 MRRE assets) agrees with the proposed scope. Please see additional comments in response 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Also, please see response to question #2.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the concern identified in the Glencoe Light SAR that Requirement R1, Subpart 1.2 does not clearly identify under what conditions notified owners of BES Elements connected to BES busses, identified under Part 1.2 of PRC-002-2; are obligated to install sequence of events recording (SER) and fault recording (FR) equipment. Additionally, given the parallel posting of both the IRPTF and Glencoe Light SARs, consideration should be given to addressing these two SAR under a single project but through a multi-phased approach with the Glencoe Light scope SAR being addressed in the first phase.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support. SAR DT recommends a multi-phased approach, with Glencoe Light SAR likely being addressed first.	

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA supports the project scope to modify Requirement R1, Part 1.2 to clarify notifications – it's been unclear both what to expect in return when we send out a notification as well as what to do with a notification when we receive one. Because of this, we have done SER and DFR	

reviews on stations that were identified to us by other entities on top of completing reviews of our PRC-002-2 identified stations. More clarity is needed on what specifically must happen when you receive a notification. The standard also states that the owner must supply the data upon request, but BPA has worked with other utilities to ensure we don't have gaps. There needs to be some leeway on allowing two or more utilities to have a formal, pre-established agreement if they choose to do so. It helps save utilities on cost if they can.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support. The SAR DT will recommend that the standards drafting team consider providing this clarification.	

2. Provide any additional comments for the SAR drafting team to consider, if desired.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

While Texas RE generally supports the scope of the proposed SAR and the overall intent of the proposed project, Texas RE proposes two additional areas for consideration in the upcoming project to improve the proposed PRC-002 Standard's overall effectiveness. First, the SDT should move periodic requirements set forth in the PRC-002 Implementation Plan directly in the Standard Requirement language contained in PRC-002-2 R1.3. Second, the SDT should review the "Median Method Excel Workbook" for potential anomalies. Texas RE provides additional details on each of these items below.

Periodic Requirements in the PRC-002-2 Implementation Plan

Texas RE is concerned there is a periodic requirement in the Implementation Plan for PRC-002-2, rather than in the requirement itself. Consistent with Standard Processes Manual, Section 4.4.3, implementation plans are intended to describe the proposed effective date, identify new or modified definitions, specify any prerequisite actions that need to be accomplished before entities are held responsible for compliance with the requirements, describe whether any conforming changes to other Reliability Standards will occur, and finally the Functional Entities that will be required to comply with the requirements.

In contrast to these core implementation plan elements, the PRC-002-2 implementation plan sets forth an explicit compliance periodicity that is not solely associated with registered entities' transition to compliance with the PRC-002-2 requirements. In particular, PRC-002-2, R1.3 states that TOs shall "re-evaluate buses at least once every five years and notify other owners…***and implement the re-evaluated list of BES buses as per the Implementation Plan.***" The current PRC-002-2 implementation plan in turn provides that "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 that list." When read together, therefore, the PRC-002-2 Registered Entities must continue to reference the current PRC-002-2 implementation plan in order to understand the requirement to implement the re-evaluated list of BES buses on a three-year cycle.

Texas RE recommends moving the three-year requirement from the PRC-002-2 implementation plan to the requirement language itself, as it is essentially a periodic requirement for TOs and is no longer associated with the prerequisite actions that need to be accomplished before Registered Entities are held responsible for PRC-002-2 R1.3. Such a change will provide additional clarity to registered entities as well as reduce the number of extraneous documents needed to comply with the standard.

Workbook Anomalies

In addition to explicitly incorporating the three-year BES bus re-evaluation language directly into the PRC-002-2 R1.3 requirement language, Texas RE also recommends the drafting team conduct a general re-evaluation of the "Median Method Excel Workbook" (located on the original project page) to ensure accurate evaluations. During the course of its ongoing compliance engagements, Texas RE staff discovered several potential anomalies and possible incorrect calculations throughout the Workbook. For example, Texas RE noticed the use of "SOER" (Sequence of Events Recording) within the Workbook, which had been removed from a Rationale dialog box in a May 2014 redline:

(https://www.nerc.com/pa/Stand/Project%20200711%20Disturbance%20Monitoring%20DL/PRC-002-2_Disturbance_Monitoring_2014May09_redline.pdf).

Texas RE staff also determined the same number of bus placements based on the example data but that number **differed** from the example provided within the Workbook. When using real world data, it was discovered that there may not be enough guidance to determine bus placement in a repeatable fashion as Workbook instructions appeared to not consider repeat values for three phase short circuit (e.g. multiple busses having the same short circuit values).

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR is revised to move periodic requirements set forth in the PRC-002 Implementation Plan in the standard as a requirement language. Review of "median method excel workbook" is not in the scope of this SAR. Revision to standard in response to IRPTF SAR may revise the methodology in attachment 1, and if so, SDT may review of the "median method excel workbook" and revise as necessary.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI looks forward to reviewing a future Project 2021-04 SAR, which contains elements of both SARs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Additionally, SAR DT recommends a multi-phased approach, with Glencoe Light SAR likely being addressed first.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	
Capital Power (on behalf of Decatur Energy Center and other Group 80 MRRE assets) appreciates any opportunity to reduce the administrative burden related to certain Reliability Standards. However, in this case, the notification of only the impacted entities may result	

in instances where, due to an administrative error, a potentially in-scope entity is not notified and assumes it is out of scope because no notification was received. To mitigate this risk, Capital Power recommends one of the following solutions: • Comprehensive, easily accessible list of all in-scope buses as well as what data is required ○ This will allow all entities, including those who may not have received a direct notification, to ensure that the lack of notification was not due to an administrative error ○ Ideally this list should be stored and/or facilitated on/via a centralized system such as NERC's Align system. • Positive confirmation of out of scope – TOs should notify all entities of their in-scope or out of scope status • Develop selection criteria specific to generators (inclusive of synchronous and inverter-based resources). Based on these criteria generators would be accountable and have the mechanism to make their own determination re. which assets require SER and FR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In regards to R1, TO is in ideal position to develop a list of buses in scope. If not notified by TO, then R2 and R3 does not apply and hence there is no risk of non-compliance. R2 and R3 includes details of data. The SAR DT does not agree that list of in-scope buses should be stored/facilitated via a centralized system such as NERC's align system. Requiring TOs to notify entities whose BES elements are not in scope of R1 is unnecessary burden on the TO. Criteria inclusive of sychornous and inverter-based resources is outside the scope of this SAR. The impact of growing penetration of IBRs is addressed by the NERC IRPTF SAR.	
Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	

Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI's comment.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
In general PRC-002 is loosely written. BPA has submitted questions to WECC for clarification. R4.3 states "Trigger settings for at least the following: 4.3.1 Neutral (residual) over current. 4.3.2 Phase undervoltage or overcurrent"; this can be interpreted that the XFMR can have a phase undervoltage trigger even though R3 states: "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."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. R4.3 specifies trigger settings to record electrical quantities specified in R3. The SAR DT feels these comments are not in scope for this SAR effort. The Guideline section for R4 provides some clarification for the triggering minimum requirements. The	

drafting team feels this is sufficient at this time, however the standard does not restrict owners from employing other triggering mechanisms in addition to the minimum requirements.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	

Reclamation recommends the PRC-002 SAR include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items:

- In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators.
- Requirement R1.3 should be modified to state the timeframe within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO).
- Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.
- Reclamation recommends adding the sharing of protection system data when requested by the entity performing the R1 evaluation.
- Requirement R12 should be modified to add a required time limit within which to notify the Regional Entity(ies) of a failure of the recording capability. Regional Entities need to know as soon as the failure occurs or is discovered, not up to 90 days later.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. SAR is revised and recommends the Standard DT to consider adding Planning Coordination to the Western Interconnection Responsible Entities, if appropriate. The time limit for notified entity per R1.3 and R5.4 is included in the implementation plan. The implementation plan states that entities shall be 100 percent compliant within three (3) years following the notification. This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan. The SAR is revised to move the three-year requirement from the PRC-002-2 implementation plan to the standard as a requirement language itself. The SAR DT disagrees with recommendation to add the sharing of protection system data with entity performing R1 evaluation. Not sure why protection system data is necessary to do re-evaluation in R1.3. SAR DT disagrees with need to revise Requirement R12 to reduce allowable time from 90 day period. Although it does not take a long time to replace or fix failed equipment, 90 day time period is necessary for unforeseen circumstances. The regional entity is only needed to be informed with a corrective action plan for information in case responsible entity is audited and does not have data available from the location where equipment failed.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

William Steiner - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	

- MRO has noted that the standard is complicated and difficult to interpret. Proper interpretation requires a nuanced understanding of various terms including "BES bus", "BES Element", "connected", and "directly connected." These terms are defined by a combination of the NERC Glossary of Terms and the standard itself. The uses of these terms in the standard provide further insight into how the terms should be understood. A more straightforward approach to defining terms in the standard would likely help to clarify the locations where recording is required as well as the delineation of responsibilities for obtaining data.

- The SAR includes the statement "the current standard could be interpreted that generation, transformer and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus" and implies that this is somehow an unnecessary or undesirable interpretation. However, it is MRO's opinion that this is the proper interpretation as R3 does not dictate the exact location of current measurement, only that the entity must have current data for the applicable transmission lines and transformers. If, for some reason, the only location where current sensing and recording equipment was installed was at the remote end of a transmission line or transformer, it would make sense to utilize that equipment rather than require installation of new equipment nearer to the identified BES bus.

- Clarifications regarding the current version of the standard and MRO’s interpretation:

  - R1.2 notifications do not obligate entities to have data, only R3 does that. The notifications ensure that BES Element owners with R3 obligations are aware of those obligations. An overreaching notification from the identified BES bus owner to an adjacent owner of equipment that does not meet the criteria given in R3 would not create any compliance obligation for the adjacent owner.

  - R1.2 and R3 are consistent with each other in addressing BES Elements "connected to the BES buses identified in Requirement R1."

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. SAR is revised and now states that terms such as such as “connected” and “directly connected” BES Elements should be clarified and as necessary, ensure consistent usage of terms such as “BES bus” and “BES Element” in the standard. Some examples are added in the revised SAR to illustrate why standard should be revised to clarify the intent of R1.2 and R3.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	
Process question, with two different SAR write-ups (IRPTF from June 2020 and Glencoe Light from April 2021) out for comment, would the Standards Committee assign one SDT to both of these SARs or would the SARs be combined into one SAR?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. SAR DT recommends a multi-phased approach, with Glencoe Light SAR likely being addressed first.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	
Document Name	
Comment	

The proposal by Glencoe light does not address following issues, which should be addressed by the Standards Drafting Team on Requirement R1.

- The Requirement R1.2 obligates the notifying entity to notify the interconnecting entity about the FR or SER monitoring requirement on the interconnecting BES element(s) within 90 days of the determination of the BES buses. But it does not say anything about the obligation of the notified interconnecting entity in terms of time limits on their response or confirmation about implementing the FR/SER monitoring. There is provision to notify interconnecting FR/ER monitoring for the interconnecting BES element(s), but thereafter standard leaves it open. There is no follow-up on actual implementation of the FR/SER monitoring. The requirement should set some time limit on the notified entity to confirm/ or resolve issues if any towards implementing the FR/SER requirement. It should also address issues, when the applicable buses list of the notified interconnecting entity does not include the bus to which the interconnecting BES element in question is connecting.

- In the requirement R5, the Reliability Coordinator (RC) notifies the entities about DDR requirement. The RC should provide more details with the notification. Currently the RC notification merely includes the requirement no in the columns. It does not include why or how the requirement number was applied. For example If a notification of DDR monitoring goes to an entity under R5.1.5 (UVLS) or 5.1.2 (Stability of System Operating limits), then the standard does not clarify RC responsibility to notify other participating entities. The RC notification does not provide the details. What about the FR/SER monitoring requirement on those interconnections between entities if the buses do not figure in the 20% applicable buses list of the concerned entities?). The standard should address this.

• The requirement R1.1 should address step 8 of the algorithm in attachment 1 of the standard. For example, step 8 does not necessarily include the case of growing inverter-based resource monitoring. It has been noticed that while applying step 1-step7, the applicable buses tend to concentrate in the high MVA zones and distributed monitoring across the network does not occur. The standard or the algorithm need to be tweaked to address this issue.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The time limit for notified entity is in the implementation plan. This is also true for re-evaluated list from R1 and R5, where the implementation plan states that entities shall be 100 percent compliant within three (3) years following the notification. This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan. The SAR is revised to move the three-year requirement from the PRC-002-2 implementation plan to the standard as a requirement language itself. The SAR DT recognizes that details might be helpful to notified entity. However, Requirements R6, R7 and R8 are regardless of a reason (UVLS, SOLs etc.) for which entity is notified by the Responsible Entity to have DDR data. Hence, it is not necessary to require the notifying entity to provide details. The impact of growing penetration of IBRs is addressed by the NERC IRPTF SAR.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
N/A.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comment. The SAR DT will recommend that the standards drafting team consider providing this clarification.	

"Comments received from Jamie Johnson – California ISO"
Question 1
☒ Yes

Comments: Any clarifications to the scope of NERC registered entities responsibilities promote clarity and add to reliability activities.

Response: Thank you for your comment and support. The intent of this SAR is to provide clarity for responsible entities. The SAR DT will recommend that the standards drafting team consider revision such that responsibilities for all entities is clearly stated.

Question 2 (no additional comments)

"Comments received from Wayne Sipperly – NAGF"
Question 1

☒ **Yes**

Comments:
The NAGF agrees with the proposed scope to clarify the notification and data responsibility requirements in PRC-002 R1 and R3. The BES Elements identified for monitoring should be defined as “a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid” to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Where the intent is to ensure that the SER and FR data is available at the identified buses, the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers

Response: Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification. The revised SAR states that the standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. Clarification using these terms should also address clarifying elements local to the identified BES bus versus remote breakers.

Question 2 (additional comments)
Comments:
PRC-002 R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.

The NAGF notes that the existing PRC-002-2 Rational section regarding R3 states that an FR exception exists for “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”. This needs to be clarified with regard to PRC-002-2 Requirement 1. TOs should be required to send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

Response: Thank you for your comment. Some examples are added in the revised SAR to illustrate why standard should be revised to clarify the intent of R1.2 and R3. The revised SAR states that obligation for FR data per requirement R3 needs clarification as to if the Generator

Owner is required or not to have FR data with examples shown in figures 7 and 8. Depending on clarification of this, the notification requirement in R1.2 may be revised and one alternative is to require TO to send separate SER and FR notifications.

"Comments received from Pamela Hunter – Southern Company"
Question 1
☒ **Yes**

Comments:
The notification and data responsibility requirements in PRC-002 R1 and R3 needs clarification.

The BES Elements identified for monitoring should be defined as "a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid" to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Where the intent is to make sure that the SER and FR data is available at the identified buses, the connected BES Elements should be limited to BES Elements local to the identified BES buses and not include transmission lines and their remote breakers.

Response: Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification. The revised SAR states that the standard should clearly define the terms "directly connected" versus "connected" as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. Clarification using these terms should also address clarifying elements local to the identified BES bus versus remote breakers.

Question 2 (additional comments)
Comments:
R1.2 should be further clarified to reduce needless administrative burden and state that notifications are only required when the Transmission Owner at the local bus needs data from the owner of the connected BES Element. Notifications stating that no data is required are an unnecessary administrative burden for the sender and recipient.

The usual order of precedence for NERC standards is that the Rationale section only explains the requirements and does not modify them.

PRC-002-2 breaks this rule by treating SER and FR in a one-size-fits-both fashion in R1, then saying in the Rationale section that an FR exception exists for, ‘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.’ It is awkward to have a letter from the TO saying that FR is required, and having to point-out to auditors that the Rationale section of PRC-002-2 overrules. PRC-002-3 should have TOs send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

Response: Thank you for your comment. Some examples are added in the revised SAR to illustrate why standard should be revised to clarify the intent of R1.2 and R3. The revised SAR states that obligation for FR data per requirement R3 needs clarification as to if the Generator Owner is required or not to have FR data with examples shown in figures 7 and 8. Depending on clarification of this, the notification requirement in R1.2 may be revised and one alternative is to require TO to send separate SER and FR notifications.

“Comments received from Daniel Gacek – Exelon”
Question 1
☒ **Yes**

Comments: Exelon agrees that the BES element owner should be responsible for data required for PRC-002-2. The BES Elements identified for monitoring should be defined as “a physical bus with breakers connected at the same voltage level within the same physical location sharing a common ground grid” to avoid including BES Elements that are remote to the identified BES bus (e.g. transmission lines and their remote terminal equipment).

Response: Thank you for your comment. The SAR DT will recommend that the standards drafting team consider providing this clarification. The revised SAR states that the standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. A few examples are added to illustrate the difference between "directly connected" and "connected" elements. Clarification using these terms should also address clarifying elements local to the identified BES bus versus remote breakers.

Question 2 (additional comments)
Comments:
Receiving notifications from a TO that data is not required for a BES Element is beneficial and such notifications should not be eliminated by changes to the standard.

Response: Thank you for your comment. Notifications when SER/FR/DDR data is not required places an unnecessary administrative compliance burden on the Responsible Entity. One of the goal of this SAR is to revise the standard to eliminate unnecessary and administrative compliance burden for the Responsible Entities.

Consideration of Comments

Project Name:	2021-04 Modifications to PRC-002-2 | IRPTF SAR
Comment Period Start Date:	6/14/2021
Comment Period End Date:	7/13/2021
Associated Ballots:	

There were 23 sets of responses, including comments from approximately 50 different people from approximately 44 companies representing 7 of the Industry Segments as shown in the table on the following pages.

All comments submitted can 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 of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

2. Provide any additional comments for the SAR drafting team to consider, if desired.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	4	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Jodi Jensen	Western Area Power Administration - Upper Great Plains East (WAPA)	1,6	MRO
					John Chang	Manitoba Hydro	1,3,6	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO

				Marc Gomez	Southwestern Power Administration	1	MRO
				Matthew Harward	Southwest Power Pool, Inc.	2	MRO
				LaTroy Brumfield	American Transmission Company, LLC	1	MRO
				Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
				Terry Harbour	MidAmerican Energy	1,3	MRO
				Jamison Cawley	Nebraska Public Power	1,3,5	MRO
				Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
				Michael Brytowski	Great River Energy	1,3,5,6	MRO
				Jeremy Voll	Basin Electric Power Cooperative	1,3,5	MRO
				Joe DePoorter	Madison Gas and Electric	4	MRO

					David Heins	Omaha Public Power District	1,3,5,6	MRO
					Bill Shultz	Southern Company Generation	5	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS does not support the scope of the SAR submitted by the NERC Inverter-based Resource Performance Task Force (IRPTF) because is too broad and does not provide specific information on the changes to be addressed by the standard drafting team. Additionally, AZPS does not agree that the IRPTF White Paper provides sufficient justification for revising the standard. AZPS's experience has shown that any significant inverter based resources tie into large substations for which the MVA requirement would cover the need for monitoring.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Despite, commenters disagreement the SAR and IRPTF white paper has been vetted by NERC IRPTF, RSTC and has broad support within the industry. APS's experiences are not necessarily indicative of many other BES areas.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	

The City of Tallahassee (TAL) believes that requiring additional monitoring equipment is not cost-effective given the minor contribution to the BES in terms of fault current. TAL is unsure how the data collected will provide a substantial gain to the BES.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Four event reviews have been documented stating additions and revisions to monitoring requirements are needed. The criteria in Attachment 1 and R5 for SER/FR and DDR data respectively mostly excludes all IBRs.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA disagrees with this project scope. PRC-002-2 Attachment 1, Step 8 already says “the additional BES buses are selected, at the Transmission Owner’s discretion, to provide maximum wide-area coverage for SER and FR data.” It then provides recommendations for selecting additional bus locations. We do not only rely on PRC-002-2 to require disturbance monitoring and recording. We have our own requirements for when to install disturbance monitoring and recording and the TO should know their system well enough to know when and where they need to monitor. In order to completely eliminate the possibility of not having data available for event analysis, you’d have to require monitoring and recording at every substation which may or may not be possible. The SAR mentions the IBRs don’t provide enough fault current, thus they can contribute to a fault. PRC-002 is for wide area faults and reconstructing them. This SAR may be better applied to PRC-023 or another protection standard. The owners need to update their own standards for SER/FR equipment or at least protective systems (most offer both limited SER/FR capability).	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Attachment 1, Step 6 limits the majority of IBR connections. Step 8 follows the limitations of step 6. The goal of SAR is not to require data for all possible events but to ensure that PRC-002 takes into account large IBR penetration in low short circuit MVA areas and address possible additional GO requirements that apply to IBRs. Not sure how revising PRC-023 or another protection standard addresses needs identified in this SAR. Additional comments addressed by Glencoe SAR (Duplicate of commenters comments submitted for Glencoe SAR)	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	

AEP believes there may be benefit in pursuing this SAR, however we do not believe that the burden to install SER, FR, and DDR should be placed on the Transmission Owner. Rather, any such obligations to do so should be placed solely on the Generator Owner of those resources.

We believe Attachment One should be revised to make it absolutely clear that it governs Transmission assets only. Generation resources deserve their own distinct selection criteria for R1 and R3, one that is inclusive of both synchronous generation and inverter based generation. Generator Owners should be able to make their determination on which assets require FR and SER solely on the resource in question, and not based on analysis regarding how that asset is compared to others. One suggested method to consider would be establishing individual and aggregate thresholds for when SER and FR would need to be installed.

While both the IRPTF SAR and the Glencoe Power and Light SAR each focus on revising PRC-002, their perceived needs and expressed goals are quite different. Because only one single SAR governs a project at any point in time, and because the unique efforts for the IRPTF SAR will likely be met with much more resistance than the Glencoe SAR, AEP recommends breaking this project into multiple phases, each with its own SAR governance. The Glencoe SAR will likely encounter less resistance from industry than the IRPTF SAR, so we recommend that the Glencoe SAR govern the first phase of the project. Once that phase is complete, the second phase could then begin with the IRPTF SAR

governing Phase 2. Pursuing Project 2021-04 this way would be much more efficient, allow progress to be made more quickly on the purpose and goal on the Glencoe SAR, and without potential delay associated to any resistance to efforts related to the IRPTF SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support. Comments appropriate for standard drafting team and will be passed to the standard drafting team. SAR DT recommends a multi-phased approach, with Glencoe Light SAR likely being addressed first.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Step 8 in Attachment 1 for R1 already provides a means by which bus locations not captured in the highest 10% bus fault current calculations are selected for SER and FR data monitoring to achieve the 20% total. Locations with Inverter Based Resources can be added to the list of recommended locations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Attachment 1, Step 8 follows the limitations of step 6 which would eliminate most IBR facilities. Additional comments in response to Question #2 to be covered by the Glencoe SAR.	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	
The rationale for R1 on page 22 explains in detail the data analysis efforts which have gone into developing a methodology for identifying optimum number of buses. The study established a strong correlation between the short circuit MVA level available at a bus and its relative size based on voltage level, no. of transmission lines and other BES elements connected have an impact on system reliability. 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. Though entities could cover the inverter-based resources under optional buses in Step 8 of the algorithm in attachment 1 of the standard.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Attachment 1, Step 8 follows the limitations of step 6 which would eliminate most IBR facilities. Observation is correct that attachment 1, steps 1 through 7 leads to list of buses with high SC MVA zone. The algorithm in attachment 1 might be tweaked by the SDT. The focus of SAR DT is on the justification to revise the standard. The requirement for TO/GO for DDR is regardless of a reason for which DDR is required under R5. It would be nice if RC provides details justifying a need of DDR, however, the SAR DT believes that is not required to be addressed by the standard. Comments to be forwarded for consideration by Standard drafting team.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
The existing standard targets BES elements with short circuit MVA in the top 20% which could leave out inverter-based resources. Recent events involving inverter-based resources (IBR), such as the Blue Cut Fire and Canyon 2 Fire, have demonstrated the need to monitor some inverter-based resources. The Project 2021-04 SAR (the portion written by the IRPTF) addresses the need to monitor some IBRs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	Yes
Document Name	
Comment	

Reclamation agrees with the addition of a requirement to further enhance SER/FR and DDR equipment in facilities on the premise that the information obtained not only enhances BES reliability but also enhances an entity's ability to troubleshoot and repair Facilities, further reduce operating costs, and increase reliability. Reclamation recommends the scope of the SAR also include the items described in the response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.	
Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Refer to response to EEI's comment.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	

Comment	
Capital Power (CP) (on behalf of Decatur Energy Center LLC and other MRRE group 80 assets) supports the NAGF submitted comments on this item.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comment.	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	

Comment	
EEI supports the concerns identified in the IRPTF SAR that current processes contained within PRC-002-2 (Attachment 1) used to identify BES buses where sequence of event (SER) and fault recording (FR) equipment are to be installed generally do not require the placement of this equipment on buses where IBR resources are prevalent. The SAR SDT should consider the potential fault recording differences that may be required by IBRs, such as the possible need for faster sampling rates for IBRs, while providing little value for synchronous resources. EEI also suggests SER and FR equipment might be efficiently placed at the point of aggregation where this information would be more useful. Additionally, given the parallel posting of both the IRPTF and Glencoe Light SARs, consideration should be given to addressing these two SAR under a single project but through a multi-phased approach with the Glencoe Light scope SAR being addressed in the first phase.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Details of where the DME is placed and potential fault recording differences that may be required by IBRs (such as possible need for faster sampling etc.) to be addressed by the standard drafting team. Your comments will be passed on to the standard drafting team. SAR DT is considering a multi-phased approach, with Glencoe Light SAR likely being addressed first.	

2. Provide any additional comments for the SAR drafting team to consider, if desired.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI looks forward to reviewing a future Project 2021-04 SAR, which contains elements of both SARs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Details of where the DME is placed and potential fault recording differences that may be required by IBRs (such as possible need for faster sampling etc.) to be addressed by the standard drafting team. Your comments will be passed on to the standard drafting team. SAR DT is considering a multi-phased approach, with Glencoe Light SAR likely being addressed first.	
Shannon Ferdinand - Decatur Energy Center LLC - 5	
Answer	
Document Name	
Comment	
Capital Power (CP) (on behalf of Decatur Energy Center LLC and other MRRE group 80 assets) supports the NAGF submitted comments on this item. In addition, CP supports Reclamation's recommendation of the following (modified slightly):	

PRC-002 SAR should include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items:

- In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators.
- Requirement R1.3 should be modified to state the timeframe / implementation period within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO).
    - This is particularly important when it comes to newly identified BES buses in remote areas where DDR equipment may not already be on-site and will need to be designed, procured, and installed.
- Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.
- The addition of a requirement allowing exemption based on equipment limitation, age of asset etc. If a newly identified BES Bus happens to be connected to an existing asset nearing the end of its useful life, the cost / benefit of the installation of additional DDR equipment should be considered.

Likes 0	
Dislikes 0	

Response

Thank you for your support and comment.

Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.

Alan Kloster - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - MRO	
Answer	

Document Name	
Comment	
Evergy supports and incorporates by reference Edison Electric Institute's (EEI) response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Details of where the DME is placed and potential fault recording differences that may be required by IBRs (such as possible need for faster sampling etc.) to be addressed by the standard drafting team. Your comments will be passed on to the standard drafting team. SAR DT is considering a multi-phased approach, with Glencoe Light SAR likely being addressed first.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
In general, PRC-002 is loosely written. BPA has submitted questions to WECC for clarification. R4.3 states "Trigger settings for at least the following: 4.3.1 Neutral (residual) over current. 4.3.2 Phase undervoltage or overcurrent"; this can be interpreted that the XFMR can have a phase undervoltage trigger even though R3 states: "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."	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Attachment 1, Step 6 limits the majority of IBR connections. Step 8 follows the limitations of step 6. The goal of SAR is not to require data for all possible events but to ensure that PRC-002 takes into account large IBR penetration in low short circuit MVA areas and address possible additional GO requirements that apply to IBRs. Not sure how revising PRC-023 or another protection standard addresses needs identified in this SAR. Additional comments addressed by Glencoe SAR (Duplicate of commenters comments submitted for Glencoe SAR)	
Richard Jackson - U.S. Bureau of Reclamation - 1,5	
Answer	
Document Name	
Comment	
Reclamation recommends the PRC-002 SAR include provisions to modify Section 4.1, Requirement R1, Requirement R5, and Requirement R12 to address the following items: • In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1.3 should be revised to include Planning Coordinators. • Requirement R1.3 should be modified to state the timeframe within which entities must be compliant with R2, R3, R4, R10, and R11 for any equipment added as a result of the TO's re-evaluation (i.e., within 3 years following the notification by the TO). • Requirement R5.4 should be modified to state the timeframe within which entities must be compliant with R6, R7, R8, R9, R10, and R11 for any equipment added as a result of the Responsible Entity's re-evaluation (i.e., within 3 years following the notification by the Responsible Entity that re-evaluated the list). Alternatively, each requirement (R6 through R11) should state the time period after notification within which the required activity must be completed as a result of changes to the TO's or Responsible Entity's list.	

• Reclamation recommends adding the sharing of protection system data when requested by the entity performing the R1 evaluation. • Requirement R12 should be modified to add a required time limit within which to notify the Regional Entity(ies) of a failure of the recording capability. Regional Entities need to know as soon as the failure occurs or is discovered, not up to 90 days later.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Despite, commenter's disagreement the SAR and IRPTF white paper has been vetted by NERC IRPTF, RSTC and has broad support within the industry. APS's experiences are not necessarily indicative of many other BES areas.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5 - WECC	

Answer	
Document Name	
Comment	

The proposal from IRPTF does not address following issues, which the Standards Drafting Team (SDT) should consider.

- The requirement R1.1 should address step 8 of the algorithm in attachment 1 of the standard. For example, step 8 does not necessarily include the case of growing inverter-based resource monitoring. It has been noticed that while applying step 1-step7, the applicable buses tend to concentrate in the high MVA zones and distributed monitoring across the network does not occur. The standard or the algorithm need to be tweaked to address this issue.

- The algorithm could adopt the weighted points technique considering MVA, Voltage, NO. of lines, IROL (Interconnection Reliability Operating Limit) and SOL (Stability Operating Limit), UVLS schemes, and Vegetation parameters to derive a distributed FR/SER/DDR monitoring.

- Standard should address follow through action by notified entities participating in interconnection with the notifying entity in a time bound way to ensure adequate FR/SER/DDR monitoring in zones, where multiple entities are involved. DDR notification by Reliability Coordinators (RC) should have more details justifying the DDR requirement than merely quoting the requirement nos. in the notification document.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Attachment 1, Step 8 follows the limitations of step 6 which would eliminate most IBR facilities.

Observation is correct that attachment 1, steps 1 through 7 leads to list of buses with high SC MVA zone. The algorithm in attachment 1 might be tweaked by the SDT. The focus of SAR DT is on the justification to revise the standard.

The requirement for TO/GO for DDR is regardless of a reason for which DDR is required under R5. It would be nice if RC provides details justifying a need of DDR, however, the SAR DT believes that is not required to be addressed by the standard. Comments to be forwarded for consideration by Standard drafting team.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
Expand the scope to add an implementation period for newly identified BES buses. During five year reviews, new BES buses are identified, and particularly in the case of BES buses like ones that may be identified as a result of this SAR that are interconnected at remote areas of the system, DDR equipment may not already be on-site and will need to be designed, procured, and installed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Additional comments in response to Question #2 to be covered by the Glencoe SAR.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy does not have comments at this time.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	

Answer	
Document Name	
Comment	
PRC-002-2 says in Requirement R1.2 that TOs shall, "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." The expression "and/or" suggests that the two forms of DME might not be automatically conjoined; there could be cases in which need to install SER does not mean that FR is required also. This point is left hanging, though, in the PRC-002-2 Att. 1 methodology for selecting buses. The rules apply to, "SER and FR data," together, not individually. The issue is not clarified until one gets to the Rationale section of PRC-002-2, which confirms that there are SER-but-not-FR exceptions, "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." Talen Energy proposes that the FR exemption for GSUs and GSU-to-TO HV lines be stated in the Applicability section of PRC-002-3. The Rationale section of the standard should explain but not modify the Requirements section.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Additional comments provided with response to Question 2 will be forwarded to standard drafting team for consideration and falls in scope of the Glencoe SAR.	

"Comments received from Jamie Johnson – California ISO"
Question 1

☒ Yes

Question 2 (no additional comments)

“Comments received from Wayne Sipperly – NAGF”
Question 1
☒ **Yes**

Comments:
The NAGF supports the SAR project scope to ensure that sequence of events recording (SER), fault recording (FR) and dynamic Disturbance recording (DDR) devices are installed and periodically assessed for certain inverter-based resources (IBRs) thus providing adequate data to facilitate analysis of BES disturbances.

Response: Thank you for your support and comment.

Question 2 (additional comments)
Comments:
Consider modifying the scope to add an implementation period for any newly identified BES buses. During five year reviews, new BES buses may be identified. DDR equipment may not already be on site and time is required for the design, procurement of material, and for installation.

The NAGF notes that the existing PRC-002-2 Rational section regarding R3 states that an FR exception exists for “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”. This needs to be clarified with regard to PRC-002-2 Requirement 1. TOs should be required to send separate SER and FR notifications, taking into account the exception for generator interconnection facilities.

Response: Thank you for your support and comment. Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.

“Comments received from Pamela Hunter – Southern Company”

Question 1
☒ **No**

Comments:
Changes to the standard are not necessary for IBR facilities. Step 8 in Attachment 1 for R1 already provides a means by which bus locations not captured in the highest 10% bus fault current calculations are selected for SER and FR data monitoring to achieve the 20% total. Locations with Inverter Based Resources can be added to the list of required locations at the Transmission Owner's discretion.

Response: Thank you for your comment. Attachment 1, Step 6 limits the majority of IBR connections. Step 8 follows the limitations of step 6.

Question 2 (additional comments)
Comments:
Modify the scope to add an implementation period for any newly identified BES buses. During five-year reviews, new BES buses may be identified. DDR equipment may not already be on site and time is required for the design, procurement of material, and for installation.

Response: Thank you for your comment. Additional comments provided with response to Question 2 to be addressed by the Glencoe SAR.

"Comments received from Daniel Gacek – Exelon"
Question 1
☒ No

Comments: While Exelon does not support the SAR in its current form, Exelon does support the concerns raised by the IRPTF regarding the need to place disturbance monitoring equipment (DME) closer to inverter-based resources (IBR). In addition to placing DME closer to IBRs, the specifications of the disturbance monitor equipment for IBRs will need to be developed to ensure data is sufficient to analyze system disturbances involving IBRs. The present PRC-002 methodology and disturbance monitoring equipment technical specifications, which is being implemented, serve conventional generation and buses remote from IBR well and those specifications should be preserved. Therefore, the SAR should be revised to specifically address the changes needed for IBR without altering the specifications for other resources.

Response: Thank you for your comment. Commenter appears to agree with the spirit of the SAR but voted no due to lack of specificity in the SAR. However, the SAR has been vetted by NERC IRPTF, RSTC and has broad support within NERC and the industry.

The SARS intention is not to make significant changes to conventional generation requirements and is directed towards specifically addressing the integration of IBR's in the BES.

The SAR's lack of more detailed specificity is to allow the standard drafting team leeway to evaluate solutions based on NERC reports and the drafting of IEEE P2800.

Question 2 (additional comments)
Comments:
In the interest of system reliability and event analysis the responsible entities should be required to install DMEs in locations that would render the greatest amount of data for system analysis. For installations involving multiple IBRs that location may include an aggregation point such as the Point of Interconnection (POI) with the transmission system or transmission substation beyond the POI.

Response: Thank you for your comment. Commenter appears to agree with the spirit of the SAR but voted no due to lack of specificity in the SAR. However, the SAR has been vetted by NERC IRPTF, RSTC and has broad support within NERC and the industry.

The SARS intention is not to make significant changes to conventional generation requirements and is directed towards specifically addressing the integration of IBR's in the BES.

The SAR's lack of more detailed specificity is to allow the standard drafting team leeway to evaluate solutions based on NERC reports and the drafting of IEEE P2800.

Additional comments will be forwarded to Standard Drafting Team.

"Comments received from Brandon Gleason – ERCOT
☒ Yes

Comments: None

Question 2 (None)

Unofficial Nomination Form

Project 2021-04 Modifications to PRC-002-2

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Friday, July 30, 2021.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 404-446-9618.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Modifications to PRC-002-2

The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The "IRPTF Review of NERC Reliability Standards White Paper" was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed.

The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR) data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES).

In addition, Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data and implicitly obligates these transformer or transmission line BES Element owners to either:

1. work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on for compliance, or
2. the transformer or transmission line BES Element owner must install its own equipment that is duplicative to the identified BES Bus recording equipment.

The goal of the proposed project is to clarify the necessary notifications in Requirement R1, Part 1.2 relative to FR data, and clearly identify the BES Element owners that need to have FR data for transformers and transmission lines with the associated identified bus.

Standards affected: PRC-002-2

The time commitment for this project is expected to be one meeting per quarter (on average two and a half full working days each meeting) with calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome. NERC is seeking individuals who have subject matter expertise with Protection & Controls and are familiar with NERC Standard PRC-002.

Name:	
Organization:	
Address:	
Telephone:	
Email:	
Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):	
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):	
Acknowledgement that the nominee has read and understands both the *NERC Participant Conduct Policy* and the *Standard Drafting Team Scope* documents, available on NERC Standards Resources. ☐ Yes, the nominee has read and understands these documents.	

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ MRO ☐ NPCC ☐ RF	☐ SERC ☐ Texas RE ☐ WECC	☐ 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	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

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:		Email:	
Name:		Telephone:	
Organization:		Email:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

UPDATED

Standards Announcement

Project 2021-04 Modifications to PRC-002-2

Nomination Period Now Open through July 30, 2021

Now Available

Nominations are being sought for Standard Authorization Requests (SARs) drafting team members. The due date has been extended, and is now open through **8 p.m. Eastern, Friday, July 30, 2021**.

Use the electronic form to submit a nomination. Contact Linda Jenkins regarding issues using the electronic form. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

The time commitment for this project is expected to be one meeting per quarter (on average two and a half full working days each meeting) with calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome. NERC is seeking individuals who have subject matter expertise with Protection & Controls and are familiar with NERC Standard PRC-002.

Previous drafting or review team experience is beneficial, but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the SAR drafting team in August 2021. Nominees will be notified shortly after they have been appointed.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email), or at 404-446-9618. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the

"Service" drop-down menu and specify “Project 2021-04 Modifications to PRC-002-2” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	April 8, 2021 (Revised on November 16, 2021)		
SAR Requester			
Name:	Terry Volkmann (Revised by Project 2021-04 SAR Drafting Team)		
Organization:	Glencoe Light and Power NCR11444		
Telephone:	612-419-0672	Email:	terrylvolkmann@gmail.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The purpose of PRC-002-2[1] is to have adequate sequence of events recording (SER) and fault recording (FR) data available to facilitate analysis of Bulk Electric System[2] (BES) disturbances. Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data andimplicitly obligates these transformer or transmission line BES Element owners to either:			

[1] NERC Reliability Standard PRC-002-2 Disturbance Monitoring and Reporting Requirements (https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&Jurisdiction=United%20States) .

[2] See Glossary of Terms Used in NERC Reliability Standards (https://www.nerc.com/files/glossary_of_terms.pdf).

Requested information
1. Work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on forcompliance, or 2. Install its own equipment that isduplicative to the identified BES Bus recording equipment. Below is Requirement R1 for reference: **R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-termPlanning] **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, within90-calendar days of completion of Part 1.1, that those BES Elements **require** SER dataand/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 there-evaluated list of BES buses as per the Implementation Plan. Notifications for FR data are being sent to BES Element owners that extend well beyond the BES bus boundary described in PRC-002-2 Attachment 1 as “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.” Notifying BES Element owners beyond this boundary unnecessarily obligates the BES Element (i.e., transformer or transmission line) owner to Requirement R3, including joint owners. The PRC-002-2 implementation plan states “Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 and R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated the list.” This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan. Moving the three-year requirement from the PRC-002-2 implementation plan to the standard as a requirement language itself will provide clarity to Responsible Entities. Requirement R1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with R1.1. Depending on results of this re-evaluation, location at which SER/FR data is required could change due to minor change in three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on methodology in Attachment 1. The standard currently does not give any guidance on what is considered a substantial change in three phase short circuit MVA. Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations would help with associated cost and compliance burden. If appropriate, add Planning Coordinator to the Western Interconnection in Section 4.1.3 as a Responsible Entity.

Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal of the proposed project is to: • Clarify the necessary notifications in Requirement R1, Part 1.2 relative to the SER/FR data, and clearly identify the BES Element owners that need to have SER/FR data for transformers and transmission lines with the associated identified bus. • Move requirement to be 100 percent compliant within three (3) years following notification of a re-evaluated list by the responsible entity from the implementation plan to the standard itself. • Add a criterion that constitutes a substantial change in fault current levels which would require changing SER/FR data recording locations. • If appropriate, add Planning Coordinator to the Western Interconnection in Section 4.1.3 as a possible Responsible Entity.
Project Scope (Define the parameters of the proposed project):
The scope should include: • Modifying Requirement R1, Part 1.2 to clarify notifications, which may include but is not limited to separating the notifications for SER data and/or FR data. Additionally, Requirement R3 should be modified so that it is abundantly clear to the applicable Transmission Owner and Generator Owner when their BES Element must have FR data for an applicable transformer or transmission line. • Clarifying various terms such as “connected” and “directly connected” BES Elements and as necessary, ensure consistent usage of terms such as “BES bus” and “BES Element” in the standard. • Codifying the three (3) year implementation period of newly identified buses in the re-evaluation performed per Requirement R1, Part 1.3 and R5.4 of the standard. The SDT should also clarify if this implementation period is three calendar years or three years from the notification from the responsible entity. • Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations. • If appropriate, adding Planning Coordinator to the Western Interconnection in Section 4.1.3 as a possible Responsible Entity.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[3] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The Transmission Owner (TO) applying the method in Attachment 1 who identifies a BES bus is in the ideal position to know which BES Elements (i.e., circuit breakers, transformer and transmission line) are connected to a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. Additionally, the identified BES

[3] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
bus owner should know who owns the particular BES Element (i.e., circuit breaker) that needs SER and FR data to capture disturbances on generators, transformers, and transmission lines as identified in Requirement R3. Owners of BES Elements beyond the physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid should not be notified, unless their SER and FR data is needed to complete the identified BES bus SER and FR data. Requirement R1, Part 1.1 uses a method and BES bus definition[4] outlined in Attachment 1 to identify BES buses that requires SER data and/or FR data. Part 1.2 requires the notification of other BES Element owners connected to the identified BES bus under Requirement R1, Part 1.1. As currently written, a notification is required regardless of whether the identified BES bus owner has FR data for the intended BES Element (i.e., transformer or transmission line) or owns the BES Elements directly connected to the identified BES bus. Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. This will eliminate unnecessary notifications and obligations of the transformer and transmission line owners to compel other entities to have SER and FR data when there is no authority to do so. In these cases, the other BES Element owner(s) have to rely on SER and FR data from another entity that does not have the obligation under the standard. Additionally, clarifying the BES Element for which SER and FR data is required will reduce auditing needs resulting from notifying BES element owners who should not be responsible to have SER and FR data as well as reducing the cost burden of meeting the reliability need for SER and FR data. The standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. PRC-002-2 uses “connected” in Requirements R1.2 and R3, however, “directly connected” is used in Requirement R2. One interpretation of “connected” versus “directly connected” is shown in Figure 1, where all breakers are considered “directly connected” and other BES elements such as transmission lines, transformers and generators are “connected” to the bus. Figure 2 shows an example of a ring bus arrangement with possible classification of “connected” and “directly connected” BES elements.

[4] Attachment 1, 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.

Requested information

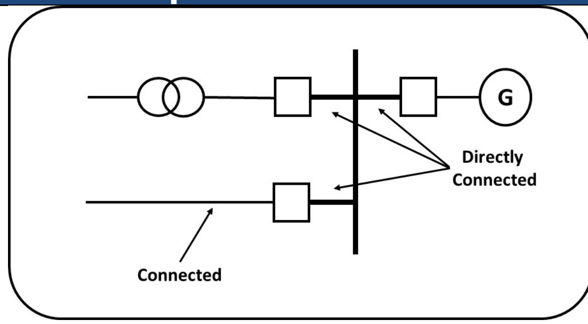


Figure 1

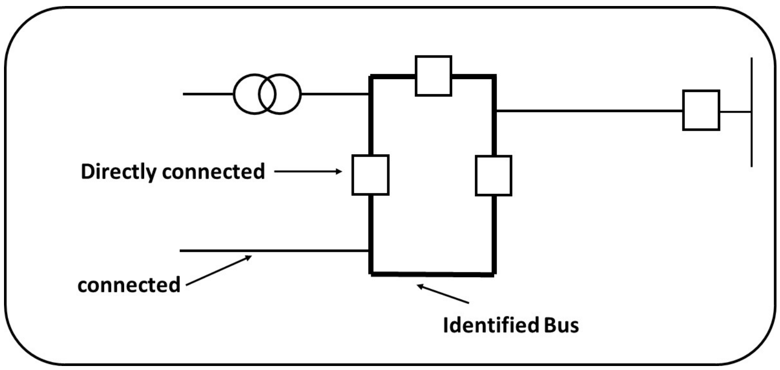


Figure 2

A straight bus configuration shown in Figure 3 is the simplest BES bus configuration sharing a common ground grid. Only the BES circuit breakers “1”, “2” and “3” are “directly connected” to the identified BES bus.

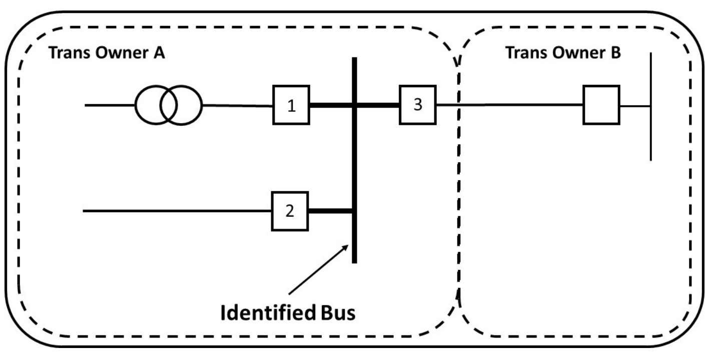


Figure 3

In this case, Transmission Owner A owns the BES bus as well as all breakers “directly connected” to it. In case where this BES bus is identified in Requirement R1, then Transmission Owner A is responsible for recording SER and FR data per Requirements R2 and R3 respectively. The Transmission Owner A should not be required to notify Transmission Owner B under Requirement R1.2 because Transmission Owner B does not own a BES element “directly connected” to the identified bus. However, per currently written Requirement R1.2, Transmission Owner A is required to notify Transmission Owner B. This has

Requested information
resulted in unnecessary notifications per Requirement R1.2 among various entities. The same is true for a ring bus configuration shown in Figure 4.

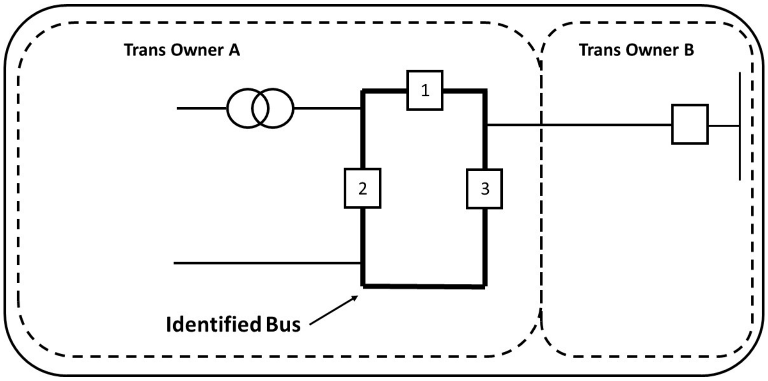


Figure 4

Figure 5 shows a variation of example in Figure 3, where BES breaker “3” is owned by Transmission Owner B. In this case, per Requirement R1.2, Transmission Owner A must notify Transmission Owner B that BES breaker “3” requires SER and FR data as breaker “3” is “directly connected” to the identified bus. In this case it is clear that SER data in Requirement R2 is required because the BES circuit breaker “3” is “directly connected” to the identified bus. Although Requirement R3 does not mention “directly connected”, it is clear that Transmission Owner B is required to have FR data to determine specified electrical quantities for breaker “3”. From there how the compliance requirement is met is up to the involved entities.

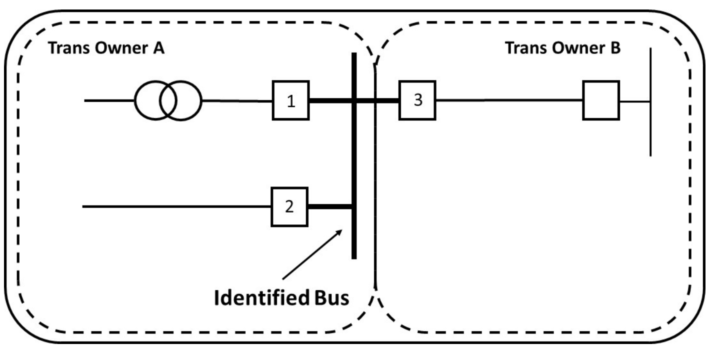
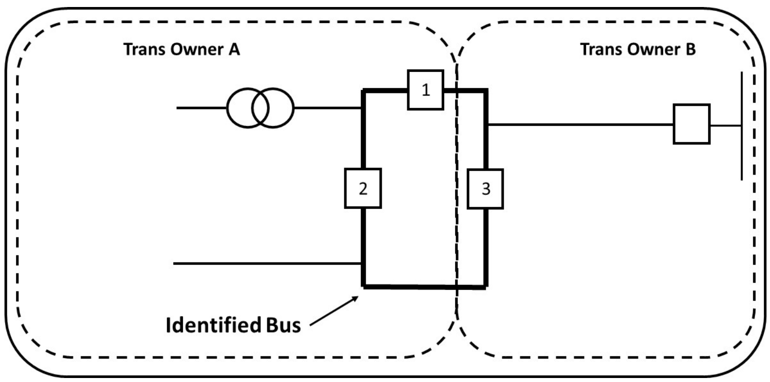


Figure 5

Under the current Requirement R1, Part 1.2, the identified BES bus owner is required to notify all owners of “directly connected” breakers that SER and/or FR data is required.

Under the current Requirement R3, the notified Transmission Owner B is required to have FR data, either by obtaining FR data from Transmission Owner A or by installing their own equipment. The Transmission Owner B cannot compel the Transmission Owner A to provide FR data. Additionally, relying on another entity for complying with PRC-002-2 places Transmission Owner B at risk if the other entity fails to have the necessary and adequate FR data.

Requested information
The intent of the standard in Requirement R3 is to have FR data associated with all applicable BES Elements at a single BES bus. This includes physical buses with breakers "directly connected" at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus. Requirement R1, Part 1.2 should only require notification to the BES Element (i.e., circuit breaker) owner "directly connected" with the identified BES bus. Under a ring bus configuration shown in Figure 6, elements (such as transmission lines, transformers etc.) that connect to the ring bus share BES circuit breakers for their protection system. The notifications per Requirement R1.2 by the identified bus owner are the same as with example in Figure 4. From there how the compliance requirement is met is up to the involved entities.  **Figure 6** If one of the connecting elements is a generator as shown in Figure 7, Requirement R2 is clear about SER data obligation for the Generator Owner and notification from Transmission Owner to Generator Owner per Requirement R1.2 should be required. However, obligation for FR data per requirement R3 needs clarification as to if the Generator Owner is required or not to have FR data for breaker "3". Requirement R3.2.1 exempts generator step-up transformers, implying that FR data would be available from equipment on the transmission system but this assumption may not be valid in all scenarios. The same clarification is also necessary for a configuration shown in Figure 8 where a generator is connected to the identified BES bus via a tie-line and the ownership of breaker "3" and the interconnecting tie-line belongs to the Generator Owner. From PRC-002-2 perspective, expectations for having FR data for breaker "3" is not different for scenarios presented in Figures 7 and 8.

Requested information

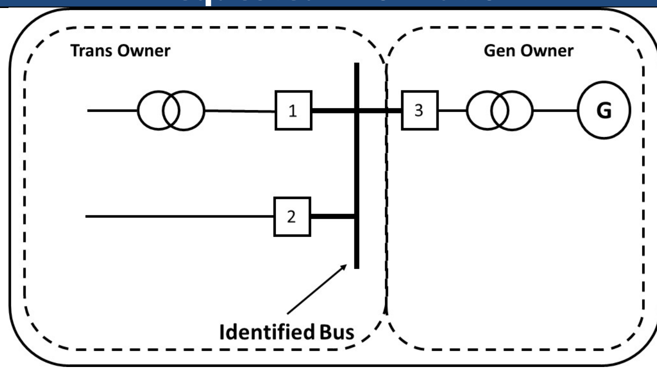


Figure 7

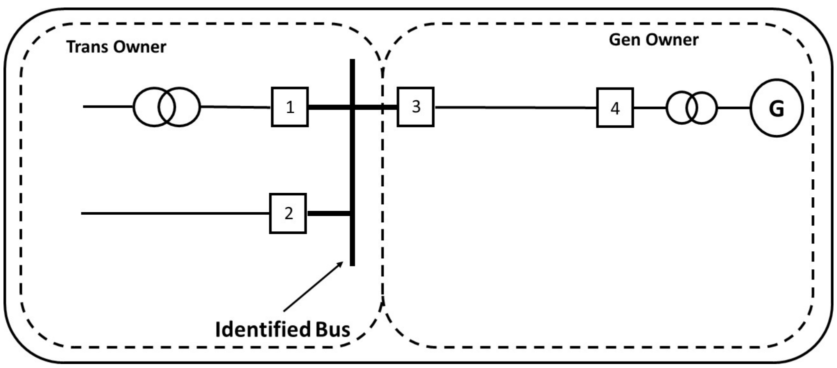


Figure 8

Identifying the appropriate BES Elements at the same voltage level within the same physical location sharing a common ground grid that requires SER and/or FR data will help facilitate obtaining data by only having to seek the data from those entities directly connected to the identified BES bus. However, the current standard could be interpreted that generation, transformer, and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus. As such, any modifications should consider alternative approaches that will achieve the intent of the standard while reducing associated cost and compliance burdens.

The PRC-002-2, R1.3 and R5.4 requires Responsible Entities to re-evaluate BES buses/BES Elements at least once every five calendar years and notify other owners…and implement the re-evaluated list of BES buses/BES Elements as per the Implementation Plan. The current PRC-002-2 implementation plan in turn requires that “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 that list.” This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan in order to understand the requirement to implement the re-evaluated list of BES buses/BES Elements on a three-year cycle. Moving the three-year requirement from the PRC-002-2 implementation plan to the standard as requirement language itself, as it is essentially a periodic

Requested information
requirement, will provide additional clarity to Responsible Entities as well as reduce the number of extraneous documents needed to comply with the standard. Requirement R1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with R1.1, which refers to methodology presented in Attachment 1. Attachment 1, Step 7 specifies that if the list has one (1) or more but less than or equal to 11 buses the FR/SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in step 3. This is applicable to small Transmission Owners. During a re-evaluation, depending on minor system changes, it is likely that a bus with a highest maximum available three phase short circuit MVA changes and would require installation of equipment to capture SER/FR data at this newly identified bus. This is justified if change in fault currents is large, however, if the change is minor then results in unnecessary burden on the Responsible Entity. Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations would help with associated cost and compliance burden.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
For most part, the proposed modifications would eliminate unnecessary and administrative compliance burden for the Responsible Entities. If the revised standard requires disturbance monitoring equipment, approximate cost would be $50,000 to $100,000 per installation unless the existing equipment is set up for monitoring and storage.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The standard already applies to TOs and GOs but depending on revision, additional generator interconnecting facilities might be required to provide FR data.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owner and Generation Owner
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
A SAR was submitted by the NERC Inverter-Baser Resource Performance Task Force (IRPTF) to address potential gaps and improvements based on the work and findings of the IRPTF was authorized for posting by the NERC Standards Committee on January 20, 2021.

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
Standard Implementation Guide or Practice Guide could provide the necessary clarity; however, these documents cannot change the strict language of the PRC-002-2 Reliability Standard. Nothing is being considered at the present time.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	April 8, 2021 (Revised on November 16, 2021)		
SAR Requester			
Name:	Terry Volkmann (Revised by Project 2021-04 SAR Drafting Team)		
Organization:	Glencoe Light and Power NCR11444		
Telephone:	612-419-0672	Email:	terrylvolkmann@gmail.com

SAR Type (Check as many as apply)	
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard	☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)

Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)	
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan	☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):
The purpose of PRC-002-2[1] is to have adequate sequence of events recording (SER) and fault recording (FR) data available to facilitate analysis of Bulk Electric System[2] (BES) disturbances. Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data andimplicitly obligates these transformer or transmission line BES Element owners to either:

[1] NERC Reliability Standard PRC-002-2 Disturbance Monitoring and Reporting Requirements (https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&Jurisdiction=United%20States) .
[2] See Glossary of Terms Used in NERC Reliability Standards (https://www.nerc.com/files/glossary_of_terms.pdf).

Requested information
1. W~~w~~ork with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on forcompliance, or 2. ~~the transformer or transmission line BES Element owner must i~~Install its own equipment that isduplicative to the identified BES Bus recording equipment. Below is Requirement R1 for reference: **R1.** Each Transmission Owner shall: [Violation Risk Factor: Lower] [Time Horizon: Long-termPlanning] **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, within90-calendar days of completion of Part 1.1, that those BES Elements **require** SER dataand/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 there-evaluated list of BES buses as per the Implementation Plan. Notifications for FR data are being sent to BES Element owners that extend well beyond the BES bus boundary described in PRC-002-2 Attachment 1 as “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.” Notifying BES Element owners beyond this boundary unnecessarily obligates the BES Element (i.e., transformer or transmission line) owner to Requirement R3, including joint owners. The PRC-002-2 implementation plan states “Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 and R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated the list.” This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan. Moving the three-year requirement from the PRC-002-2 implementation plan to the standard as a requirement language itself will provide clarity to Responsible Entities. Requirement R1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with R1.1. Depending on results of this re-evaluation, location at which SER/FR data is required could change due to minor change in three phase ~~SC~~short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on methodology in Attachment 1. The standard currently does not give any guidance on what is considered a substantial change in three phase ~~SC~~short circuit MVA. Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations would help with associated cost and compliance burden.

Requested information
If appropriate, ~~A~~add Planning Coordinator to the Western Interconnection in Section 4.1.3 as a Responsible Entity.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal of the proposed project is to: • ~~C~~clarify the necessary notifications in Requirement R1, Part 1.2 relative to the SER/FR data, and clearly identify the BES Element owners that need to have SER/FR data for transformers and transmission lines with the associated identified bus. • Move requirement to be 100 percent compliant within three (3) years following notification of a re-evaluated list by the responsible entity from the implementation plan to the standard itself. • Add a criterion that constitutes a substantial change in fault current levels which would require changing SER/FR data recording locations. • If appropriate, ~~A~~add Planning Coordinator to the Western Interconnection in Section 4.1.3 as a possible Responsible Entity.
Project Scope (Define the parameters of the proposed project):
The scope should include: • M~~m~~odifying Requirement R1, Part 1.2 to clarify notifications, which may include but is not limited to separating the notifications for SER data and/or FR data ~~regarding notification~~. Additionally, Requirement R3 should be modified so that it is abundantly clear to the applicable Transmission Owner and Generator Owner when their BES Element must have FR data for an applicable transformer or transmission line. • C~~c~~larifying various terms such as “connected” and “directly connected” BES Elements and as necessary, ensure consistent usage of terms such as “BES bus” and “BES Element” in the standard. • Codifying the three (3) year implementation period of newly identified buses in the re-evaluation performed per Requirement R1, Part 1.3 and R5.4 of the standard. The SDT should also clarify if this implementation period is three calendar years or three years from the notification from the responsible entity. • Adding a criterion that constitutes a substantial change in fault current levels which would require changing SER and FR data recording locations. • If appropriate, ~~A~~adding Planning Coordinator to the Western Interconnection in Section 4.1.3 as a possible Responsible Entity.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[3] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The Transmission Owner (TO) applying the method in Attachment 1 who identifies a BES bus is in the ideal position to know which BES Elements (i.e., circuit breakers, transformer and transmission line) are

[3] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

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connected to a single BES bus that includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. Additionally, the identified BES bus owner should know who owns the particular BES Element (i.e., circuit breaker) that needs SER and FR data to capture disturbances on generators, transformers, and transmission lines as identified in Requirement R3. Owners of BES Elements beyond the physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid should not be notified, unless their SER and FR data is needed to complete the identified BES bus SER and FR data. Requirement R1, Part 1.1 uses a method and BES bus definition[4] outlined in Attachment 1 to identify BES buses that requires SER data and/or FR data. Part 1.2 requires the notification of other BES Element owners connected to the identified BES bus under Requirement R1, Part 1.1. As currently written, a notification is required regardless of whether the identified BES bus owner has FR data for the intended BES Element (i.e., transformer or transmission line) or owns the BES Elements directly connected to the identified BES bus. Requirement R1, Part 1.2 should be modified such that only the directly connected BES Element owner to the identified BES bus at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus shall have FR data. This will eliminate unnecessary notifications and obligations of the transformer and transmission line owners to compel other entities to have SER and FR data when there is no authority to do so. In these cases, the other BES Element owner(s) have to rely on SER and FR data from another entity that does not have the obligation under the standard. Additionally, clarifying the BES Element for which SER and FR data is required will reduce auditing needs resulting from notifying BES element owners who should not be responsible to have SER and FR data as well as reducing the cost burden of meeting the reliability need for SER and FR data. The standard should clearly define the terms “directly connected” versus “connected” as it relates to determining which elements are required to have the SER and FR data. PRC-002-2 uses “connected” in Requirements R1.2 and R3, however, “directly connected” is used in Requirement R2. One interpretation of “connected” versus “directly connected” is shown in Figure 1, where all breakers are considered “directly connected” and other BES elements such as transmission lines, transformers and generators are “connected” to the bus. Figure 2 shows an example of a ring bus arrangement with possible classification of “connected” and “directly connected” BES elements.

[4] Attachment 1, 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.

Requested information

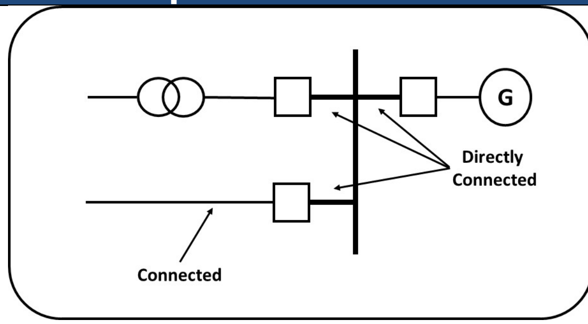


Figure 1

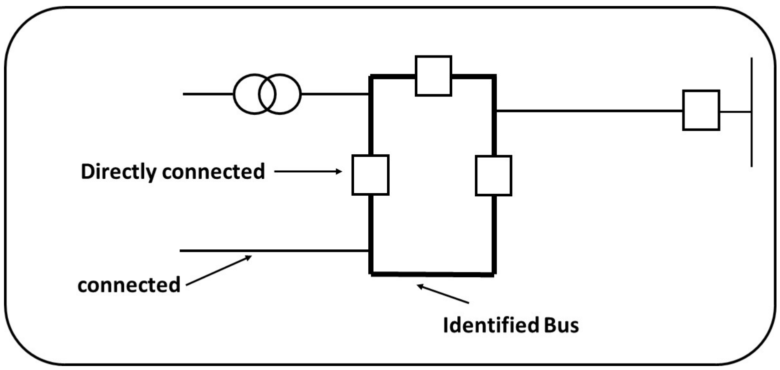
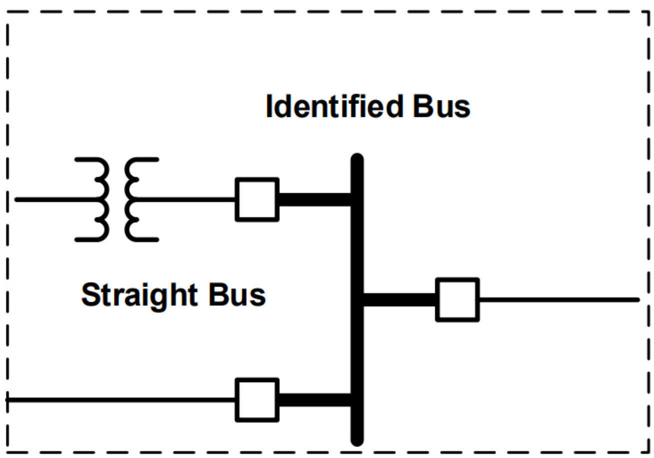
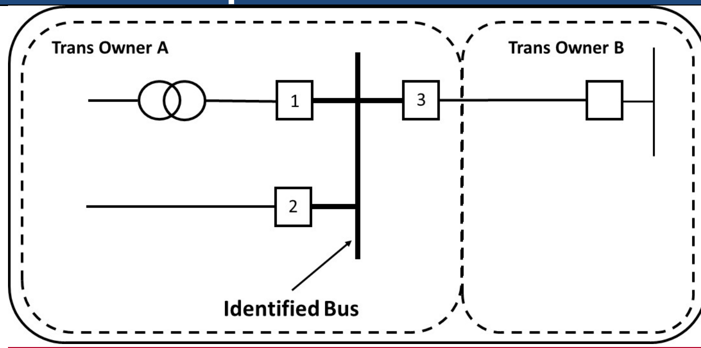
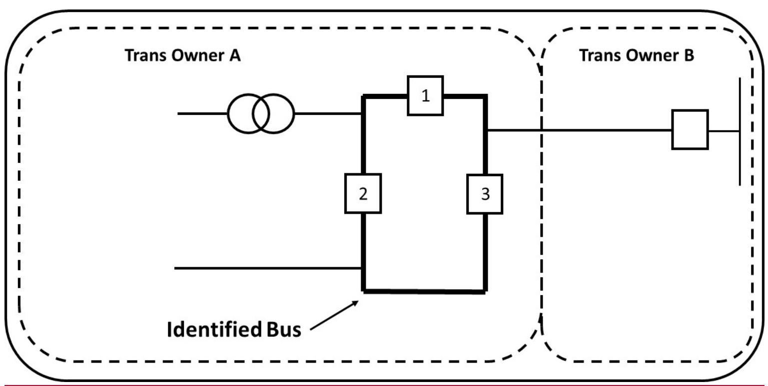


Figure 2



A straight bus configuration shown in Figure 3 ~~The above figure of a straight bus~~ is the simplest BES bus configuration sharing~~contained within~~ a common ground grid. Only the BES circuit breakers “1”, “2” and “3” are “directly connected” to the identified BES bus.

Requested information
 **Figure 3** In this case, Transmission Owner A owns the BES bus as well as all breakers "directly connected" to it. In case where this BES bus is identified in Requirement R1, then Transmission Owner A is responsible for recording SER and FR data per Requirements R2 and R3 respectively. The Transmission Owner A should not be required to notify Transmission Owner B under Requirement R1.2 because Transmission Owner B does not own a BES element "directly connected" to the identified bus. However, per currently written Requirement R1.2, Transmission Owner A is required to notify Transmission Owner B. This has resulted in unnecessary notifications per Requirement R1.2 among various entities. The same is true for a ring bus configuration shown in Figure 4.  **Figure 4** Figure 5 shows a variation of example in Figure 3, where BES breaker "3" is owned by Transmission Owner B. In this case, per Requirement R1.2, Transmission Owner A must notify Transmission Owner B that BES breaker "3" requires SER and FR data as breaker "3" is "directly connected" to the identified bus. In this case it is clear that~~concerning~~ SER data in Requirement R2 is required because the BES circuit breaker "3" is "directly connected~~.~~" to the identified bus. Although Requirement R3 does not mention "directly connected", it is clear that Transmission Owner B is required to have FR data to determine specified electrical quantities for breaker "3". From there how the compliance requirement is met is up to the involved entities.

Requested information

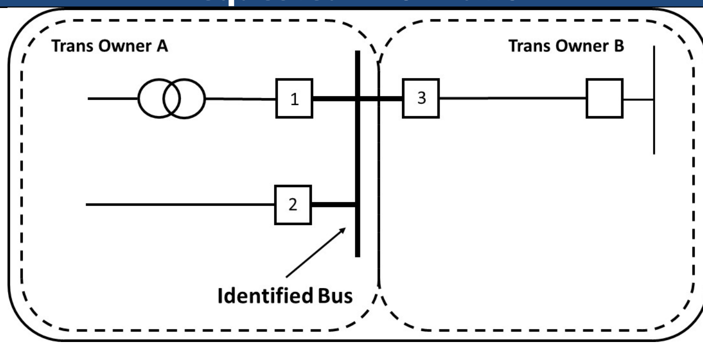


Figure 5

~~However, to achieve the need for FR data in Requirement R3, the identified BES bus owner notifies the transformer and transmission line owners under~~ Under the current Requirement R1, Part 1.2, the identified BES bus owner is required to notify all owners of ~~thus obligating them to have FR data where the circuit breaker is~~ "directly connected" breakers ~~and the logical BES Element to record~~ that SER and/or FR data is required.

Under the current Requirement R3, the notified Transmission Owner B is required to have FR data, either by obtaining FR data from Transmission Owner A~~GO and TO transformer or line owner will need to contact the circuit breaker owner in hope of obtaining FR data~~ or by installing their own equipment. The Transmission Owner B~~GO and TO~~ cannot compel the Transmission Owner A ~~circuit breaker owner~~ to provide~~have~~ FR data. Additionally, relying on another entity ~~that has no reliability responsibility~~ for complying with PRC-002-2 places Transmission Owner B~~the transformer or transmission line owner~~ at risk if the other entity fails to have the necessary and adequate FR data.

The intent of the standard in Requirement R3 is to have FR data associated with all applicable BES Elements at a single BES bus. This~~but that~~ includes physical buses with breakers "directly connected" at the same voltage level within the same physical location sharing a common ground grid of the identified BES bus. Requirement R1, Part 1.2 should only require notification to the BES Element (i.e., circuit breaker) owner "directly connected" with the identified BES bus.

Under a ring bus configuration shown in Figure 6, elements (such as transmission lines, transformers etc.) that connect to the ring bus share BES circuit breakers for their protection system. The notifications per Requirement R1.2 by the identified bus owner are the same as with example in Figure 4. From there how the compliance requirement is met is up to the involved entities.

Requested information

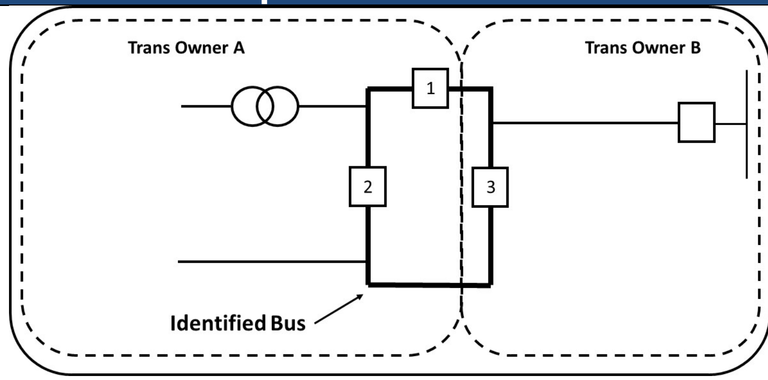


Figure 6

If one of the connecting elements is a generator as shown in Figure 7, Requirement R2 is clear about SER data obligation for the Generator Owner and notification from Transmission Owner to Generator Owner per Requirement R1.2 should be required. However, obligation for FR data per requirement R3 needs clarification as to if the Generator Owner is required or not to have FR data for breaker “3”. Requirement R3.2.1 exempts generator step-up transformers, implying that FR data would be available from equipment on the transmission system but this assumption may not be valid in all scenarios. The same clarification is also necessary for a configuration shown in Figure 8 where a generator is connected to the identified BES bus via a tie-line and the ownership of breaker “3” and the interconnecting tie-line belongs to the Generator Owner. From PRC-002-2 perspective, expectations for having FR data for breaker “3” is not different for scenarios presented in Figures 7 and 8.

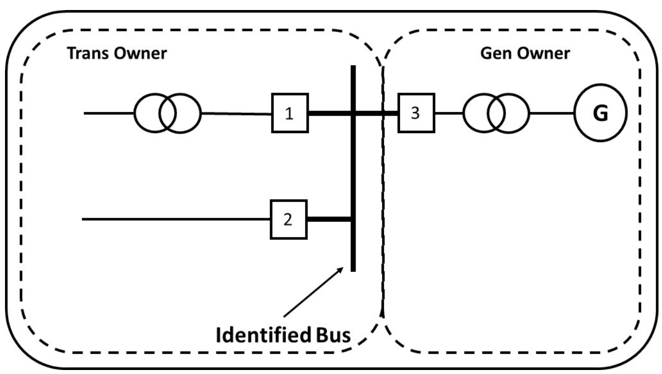
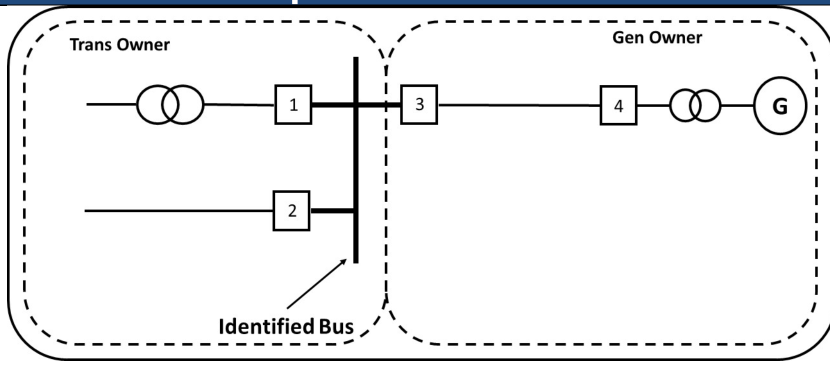


Figure 7

Requested information
 **Figure 8** Identifying ~~Having~~ the appropriate BES Elements ~~identified~~ at the same voltage level within the same physical location sharing a common ground grid that requires SER and/or FR data will help facilitate obtaining data by only having to seek the data from those entities directly connected to the identified BES bus. However, the current standard could be interpreted that generation, transformer, and transmission line owners could have FR data that is recorded at a location remote to the identified BES bus. As such, any modifications should consider alternative approaches that will achieve the intent of the standard while reducing associated cost and compliance burdens. The PRC-002-2, R1.3 and R5.4 requires Responsible Entities to re-evaluate BES buses/BES Elements at least once every five calendar years and notify other owners…and implement the re-evaluated list of BES buses/BES Elements as per the Implementation Plan. The current PRC-002-2 implementation plan in turn requires that "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 that list." This requires PRC-002-2 Registered Entities to continue to reference the current PRC-002-2 implementation plan in order to understand the requirement to implement the re-evaluated list of BES buses/BES Elements on a three-year cycle. Moving the three-year requirement from the PRC-002-2 implementation plan to the standard as requirement language itself, as it is essentially a periodic requirement, will provide additional clarity to Responsible Entities as well as reduce the number of extraneous documents needed to comply with the standard. Requirement R1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with R1.1, which refers to methodology presented in Attachment 1. Attachment 1, Step 7 specifies that if the list has one (1) or more but less than or equal to 11 buses the FR/SER data is required at the BES bus with the highest maximum available calculated three phase ~~SC~~short circuit MVA as determined in step 3. This is applicable to small Transmission Owners. During a re-evaluation, depending on minor system changes, it is likely that a bus with a highest maximum available three phase ~~SC~~short circuit MVA changes and would require installation of equipment to capture SER/FR data at this newly identified bus. This is justified if change in fault currents is large, however, if the change is minor then results in unnecessary burden on the Responsible Entity. Adding a criterion that constitutes

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a substantial change in fault current levels which would require changing SER and FR data recording locations would help with associated cost and compliance burden.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
For most part, the proposed modifications would eliminate unnecessary and administrative compliance burden for the Responsible Entities. If the revised standard requires disturbance monitoring equipment, approximate cost would be $50,000 to $100,000 per installation unless the existing equipment is set up for monitoring and storage. ~~None, the proposed modification above eliminates the unnecessary cost of being required to have FR data due to expanded notifications and the administrative burden to transformer and transmission line owners when these entities generally do not own the BES Elements that actually record the FR data.~~
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
The standard already applies to TOs and GOs but depending on revision, additional generator interconnecting facilities might be required to provide FR data~~None~~.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Transmission Owner and Generation Owner
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
A SAR was submitted by the NERC Inverter-Baser Resource Performance Task Force (IRPTF) to address potential gaps and improvements based on the work and findings of the IRPTF was authorized for posting by the NERC Standards Committee on January 20, 2021.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
Standard Implementation Guide or Practice Guide could provide the necessary clarity; however, these documents cannot change the strict language of the PRC-002-2 Reliability Standard. Nothing is being considered at the present time.

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	

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SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	June 10, 2020 (Revised on November 16, 2021)		
SAR Requester			
Name:	Allen Shriver, Chair Jeffery Billo, Vice Chair Revised by Project 2021-04 SAR Drafting Team)		
Organization:	Inverter-Based Resource Performance Task Force (IRPTF)		
Telephone:	Allen: 561-904-3234 Jeffery: 512-248-6334	Email:	Allen.Schriver@NextEraEnergy.com Jeff.Billo@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The "IRPTF Review of NERC Reliability Standards White Paper" was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed. The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR)			

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data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES). Requirements R1 and R5 are written with a focus on synchronous machine dominated systems with periodic review of monitoring equipment needs for the system. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. Inverter-based resources (IBRs) do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices. Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events. With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices and periodic assessments, the location requirements and associated periodic assessments need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise PRC-002-2 to address gaps within the existing standard. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS buses for which SER and FR data is required provides adequate monitoring of BES Disturbances. This may include updates to supplemental information such as the previously provided “Median Method Excel Workbook”. b. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS Elements for which DDR data is required provides adequate monitoring of BES disturbances.

Requested information
c. Consider other manners in which to add to, modify or clarify the existing requirements to ensure adequate monitoring of BES disturbances. d. Consider proposed IEEE P2800 monitoring requirements and NERC Odessa Disturbance Report recommendations for modification or additions to existing requirements.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data. However, BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring, though it is possible that monitoring in these areas is needed for disturbance analysis, as was the case in the Blue Cut Fire and Canyon 2 Fire events. Requirement R5, identifies BES locations based on a size criteria for generating resources and other critical elements such as HVDC, IROLs and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. In regard to generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. However, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR devices to ensure adequate coverage for disturbance analysis while balancing cost impacts.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The SAR proposes to modify PRC-002-2 requirements. The cost impact is unknown, however, the cost of disturbance monitoring hardware is approximately $50,000 to $100,000 per installation if the existing onsite equipment is not already set up for monitoring and storage.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
IBRs contribute very little short circuit MVA and are typically smaller in aggregate nameplate rating when compared to legacy synchronous resources. The criteria for selecting disturbance monitoring locations should take this into account.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinator, Reliability Coordinator, Generator Owner, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This issue was captured in the "IRPTF Review of NERC Reliability Standards White Paper" which was approved by the Operating Committee and the Planning Committee. Additionally, the IRPTF produced "BPS-Connected Inverter-Based Resource Performance"(see Chapter 6) and "Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources" reliability guidelines touch on monitoring considerations for IBRs.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
N/A
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The IRPTF did not identify any alternatives since there is a gap in PRC-002-2.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those 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.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	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.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	N/A

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SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised

1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
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Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	PRC-002-2 Disturbance Monitoring and Reporting Requirements		
Date Submitted:	June 10, 2020 (Revised on November 16, 2021)		
SAR Requester			
Name:	Allen Shriver, Chair Jeffery Billo, Vice Chair Revised by Project 2021-04 SAR Drafting Team)		
Organization:	Inverter-Based Resource Performance Task Force (IRPTF)		
Telephone:	Allen: 561-904-3234 Jeffery: 512-248-6334	Email:	Allen.Schriver@NextEraEnergy.com Jeff.Billo@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The NERC Inverter-based Resource Performance Task Force (IRPTF) undertook an effort to perform a comprehensive review of all NERC Reliability Standards to determine if there were any potential gaps or improvements based on the work and findings of the IRPTF. The IRPTF identified several issues as part of this effort and documented its findings and recommendations in a white paper. The “IRPTF Review of NERC Reliability Standards White Paper” was approved by the Operating Committee and the Planning Committee in March 2020. Among the findings noted in the white paper, the IRPTF identified issues with PRC-002-2 that should be addressed. The purpose of PRC-002-2 is to have adequate data available to facilitate analysis of BES disturbances. Requirements R1 and R5 specify where sequence of events recording (SER) and fault recording (FR)			

Requested information
data, and where dynamic Disturbance recording (DDR) data, respectively, are required in the Bulk Electric System (BES). Requirements R1 and R5 are written with a focus on synchronous machine dominated systems with periodic review of monitoring equipment needs for the system. The BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. Inverter-based resources (IBRs) do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring. In addition, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR and SER/FR devices. Recent disturbance analyses of events involving IBRs including the Blue Cut Fire and Canyon 2 Fire have demonstrated the lack of disturbance monitoring data available from these facilities and nearby BES buses to adequately determine the causes and effects of their behavior. None of the IBRs involved in these two events met the size criteria stated in PRC-002-2 to be required to have disturbance monitoring. Additionally, none of the buses near the IBRs met the criteria in Requirement R1 for being required to have SER and FR devices since the IBRs inherently produce very little fault current. This led to difficulty in adequately assessing the events. With the changing resource mix and increasing penetration of IBRs, PRC-002-2 does not serve its intended purpose adequately. To the extent that the standard is already requiring monitoring devices and periodic assessments, the location requirements and associated periodic assessments need to be revised. These revisions are necessary so that required data is available for the purposes of post-mortem event analysis and identifying root causes of large system disturbances.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This SAR proposes to revise PRC-002-2 to address gaps within the existing standard. The goal is to modify the requirements to ensure adequate data is available and periodically assessed to facilitate the analysis of BES disturbances, including in areas of the Bulk Power System (BPS) that may not be covered by the existing requirements.
Project Scope (Define the parameters of the proposed project):
The proposed scope of this project is as follows: a. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS buses for which SER and FR data is required provides adequate monitoring of BES Disturbances. This may include updates to supplemental information such as the previously provided “Median Method Excel Workbook”. b. Consider ways to ensure that the identification and periodic assessment of BES and/or BPS Elements for which DDR data is required provides adequate monitoring of BES disturbances.

Requested information
c. Consider other manners in which to add to, modify or clarify the existing requirements to ensure adequate monitoring of BES disturbances. ~~c.~~d. Consider proposed IEEE P2800 monitoring requirements and NERC Odessa Disturbance Report recommendations for modification or additions to existing requirements.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Per Requirement R1 (which uses criteria outlined in Attachment 1), Sequence of Event Recording (SER) and Fault Recording (FR) devices are required at BES buses with high short circuit MVA values. The methodology identifies the top 20 percent of BES buses with highest short circuit MVA values and requires a subset of these buses to be monitored for SER and FR data. However, BES elements with short circuit MVA in the top 20% are typically elements at baseload generating plants with multiple generating units or BES elements within a heavily meshed transmission network usually close to large load centers. IBRs do not contribute much fault current and are usually interconnected in remote parts of the system. As such, the short circuit MVA for the point of interconnection (POI) bus and nearby BES buses is not expected to be in the top 20%. Hence, BES buses near these resources are more likely to be omitted from requiring SER and FR data monitoring, though it is possible that monitoring in these areas is needed for disturbance analysis, as was the case in the Blue Cut Fire and Canyon 2 Fire events. Requirement R5, identifies BES locations based on a size criteria for generating resources and other critical elements such as HVDC, IROLs and elements of UVLS program, for which Dynamic Disturbance Recording (DDR) data is required. In regard to generation resources, it includes requirements for monitoring at sites with either gross individual nameplate rating of greater than or equal to 500 MVA or gross individual nameplate rating greater than or equal to 300 MVA where gross plant/facility aggregate nameplate rating is greater than or equal to 1000 MVA. However, most IBRs do not meet the nameplate rating criteria outlined in Requirement R5. With increasing penetration of IBRs, it is important that some of these resources and nearby BES elements are monitored with DDR devices to ensure adequate coverage for disturbance analysis while balancing cost impacts.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The SAR proposes to modify PRC-002-2 requirements. The cost impact is unknown, however, the cost of disturbance monitoring hardware is approximately $50,000 to $100,000 per installation if the existing onsite equipment is not already set up for monitoring and storage.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
IBRs contribute very little short circuit MVA and are typically smaller in aggregate nameplate rating when compared to legacy synchronous resources. The criteria for selecting disturbance monitoring locations should take this into account.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinator, Reliability Coordinator, Generator Owner, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This issue was captured in the "IRPTF Review of NERC Reliability Standards White Paper" which was approved by the Operating Committee and the Planning Committee. Additionally, the IRPTF produced "BPS-Connected Inverter-Based Resource Performance"(see Chapter 6) and "Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources" reliability guidelines touch on monitoring considerations for IBRs.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
N/A
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The IRPTF did not identify any alternatives since there is a gap in PRC-002-2.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check 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.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	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.

Market Interface Principles	
Does the proposed standard development project comply with all of the following [Market Interface Principles]?	Enter (yes/no)
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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	N/A

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal comment period with ballot	06/09/2022 – 07/15/2022
XX-day formal or informal comment period with additional ballot	09/09/2022 – 10/17/2022
XX-day final ballot	12/09/2022 – 01/16/2023
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-4

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Owner

   4.1.3. Generator Owner

5. **Effective Date:** 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-002-4, Attachment 1.

1.2. Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners of their responsibilities in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-4, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

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 directly 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 Reliability Coordinator 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 Reliability Coordinator'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. If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days.

5.4. Re-evaluate all BES Elements under its purview 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.

M5. The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator, 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) years of notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to BES buses identified during the re-evaluation.

13.2. Within three (3) years of notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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 Enforcement Program:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

Violation Severity Levels

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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar	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 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 owners that their BES Elements require SER or FR data by greater than	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

			OR The Transmission Owner as directed by Requirement R1, Part 1.2 did not notify the other owners that their BES Elements do not require SER or FR data within 90 calendar days.	days, but less than or equal to 20 calendar days.	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	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	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

			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.	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.	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 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 Reliability Coordinator 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 Reliability Coordinator identified the BES	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 did not notify the owners that their BES Elements do not require DDR data within 90 calendar days.	The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator 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	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	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	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			required electrical quantities for all applicable BES Elements.	electrical quantities for all applicable BES Elements.	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	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	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	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as

			as specified in Requirement R9.	as specified in Requirement R9.	recording properties as specified in Requirement R9.	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, 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, 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, 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 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.	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.	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 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 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

					The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	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.
R13	Long-term Planning	Lower	The Transmission Owner or Generator Owner had SER data for more than 75 percent, but less than 100 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for more than 75 percent, but less than 100 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for more than 75 percent, but less than 100	The Transmission Owner or Generator Owner had SER data for more than 50 percent, but less than 75 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for more than 50 percent, but less than or equal to 75 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for more than 50 percent, but less than or	The Transmission Owner or Generator Owner had SER data for more than 25 percent, but less than 50 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for more than 25 percent, but less than or equal to 50 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for more than 25 percent, but less than or	The Transmission Owner or Generator Owner had SER data for less than or equal to 25 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for less than or equal to 25 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for less than or equal to 25 percent of the BES Elements identified during the re-evaluation

			percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.	equal to 75 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.	equal to 50 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.	per Requirement R5, Part 5.4

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.

NERC Reliability Standard PRC-002-4: Guidelines and Technical Basis.

NERC Reliability Standard PRC-002-4: Implementation Plan.

NERC Reliability Standard PRC-002-4: Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	TBD	TBD	Revised under Project 2021-04

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.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of previously identified BES bus is within 15% of three phase short circuit MVA of the newly identified BES bus then it is not necessary to change the applicable BES bus where FR and SER data is required.

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

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45~~XX~~-day formal or informal comment period with ballot	06/09/2022 – 07/15/2022
XX-day formal or informal comment period with additional ballot	09/09/2022 – 10/17/2022
XX-day final ballot	12/09/2022 – 01/16/2023
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-~~3~~4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
5. **Effective Date:** See Implementation Plan

A. 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-~~3~~4, Attachment 1.

1.2. Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that they are responsible for recording the SER or FR data. This notification is required~~, if any,~~ within 90 ~~-~~calendar days of completion of Part 1.1~~, that those BES Elements require SER data and/or FR data~~. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 ~~-~~calendar days.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners of their responsibilities~~, 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 for Requirement R1, Part 1.1 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-~~3~~4, Attachment 1;~~,~~ has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3. ~~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 directly 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 Reliability Coordinator 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 Reliability Coordinator'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~~. If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 ~~-~~calendar days.

5.4. Re-evaluate all BES Elements under its purview 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 Reliability Coordinator 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 Reliability Coordinator 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
○ 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 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 Reliability Coordinator, 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) years of notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to BES buses identified during the re-evaluation.

13.2. Within three (3) years of notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

B. 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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.~~

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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 Enforcement Program:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Violation Severity Levels

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 that their BES Elements require SER or FR data by 10- calendar days or less. OR The Transmission Owner as directed by Requirement R1,	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 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 owners that their BES Elements require SER or FR data by greater than 10- calendar days, but less than or equal to 20- calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20- calendar days, but less than or equal to 30 -calendar days.	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 that their BES Elements require SER or FR data by greater than 30 -calendar days.

			Part 1.2 did not notify the other owners that their BES Elements do not require SER or FR data within 90~~-~~ 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 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 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 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 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 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 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 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days.

			OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 did not notify the owners that their BES Elements do not require DDR data within 90 calendar days.	days, but less than or equal to 20 calendar days.	by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator 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 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,	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8,	The Transmission Owner or Generator Owner failed to have 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.	than 70 percent, but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	for more than 60 percent, but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	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 -	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 -	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	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

			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 than 90 percent of the data, but less than 100 percent of the data in the proper data format.	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 than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	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 than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	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 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	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	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 discovery of the failure.

			-calendar days after discovery of the failure.	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.	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.
R13.	Long-term Planning	Lower	The Transmission Owner or Generator Owner had SER data for more than 75 percent, but less than 100 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for more than 75 percent, but less than 100 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for more than 75 percent, but less than 100	The Transmission Owner or Generator Owner had SER data for more than 50 percent, but less than 75 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for more than 50 percent, but less than or equal to 75 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for more than 50 percent, but less than or equal	The Transmission Owner or Generator Owner had SER data for more than 25 percent, but less than 50 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for more than 25 percent, but less than or equal to 50 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for more than 25 percent, but less than or	The Transmission Owner or Generator Owner had SER data for less than or equal to 25 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for less than or equal to 25 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for less than or equal to 25 percent of the BES Elements identified during

			percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.	to 75 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.	equal to 50 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.	the re-evaluation per Requirement R5, Part 5.4

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

F. 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).

NERC Reliability Standard PRC-002-4: Guidelines and Technical Basis.

NERC Reliability Standard PRC-002-4: Implementation Plan.

NERC Reliability Standard PRC-002-4: Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	**TBD**	**TBD**	Revised under Project 2021-04

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.
During re-evaluation per Requirement R1, Part 1.3, if the three phase short

circuit MVA of previously identified BES bus is within 15% of three phase short circuit MVA of the newly identified BES bus then it is not necessary to change the applicable BES bus where FR and SER data is required.

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

Requirement	Entity	Implementation
R13	TO | GO	X

Implementation Plan (Draft)

Project 2021-04 Modifications to PRC-002
Reliability Standard PRC-002-4

Applicable Standard(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Requested Retirement(s)

- PRC-002-3 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner
- Generator Owner

General Considerations

A definite time to implement this version of Reliability Standard PRC-002-4 is not specified because

- revisions to Requirements R1, R3, and R5 are clarifying in nature, and
- relocates the amount of implementation time prescribed in the PRC-002-2 Implementation Plan to the new Requirement R13.[1]

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-002-4 shall become effective **<u>on the later of:</u>** (1) the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard or as otherwise provided for by the applicable governmental authority; **<u>or</u>** (2) the effective date of PRC-002-3.

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-002-4 shall become effective **<u>on the later of:</u>** (1) the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction; **<u>or</u>** (2) the effective date of PRC-002-3.

[1] PRC-002-2 and PRC-002-3, Implementation Plans: "Entities shall be 100 percent compliant with new BES [Bulk Electric System] Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator."

Retirement Date

The version of Reliability Standard PRC-002 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-002-4.

Prior Implementation Plan

The elements of the Implementation Plan for PRC-002-3 are incorporated herein by reference and shall remain applicable to PRC-002-4.

Reliability Coordinators in the Eastern Interconnection shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3 or six (6) months of the effective date of PRC-002-4, whichever occurs first.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2021-04 Modifications to PRC-002

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System (SBS)]() to submit comments on **Project 2021-04 Modifications to PRC-002** by **8 p.m. Eastern, July 25, 2022.**

Additional information is available on the [project page](). If you have questions, contact Senior Standards Developer, [Ben Wu]() (via email), or at 404-446-9618.

Background Information

Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data and implicitly obligates these transformer or transmission line BES Element owners to either:

1. Work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on for compliance, or
2. Install its own equipment that is duplicative to the identified BES Bus recording equipment.

The goal of the proposed project is to clarify the necessary notifications in Requirement R1, Part 1.2 relative to FR data, and clearly identify the BES Element owners that need to have FR data for transformers and transmission lines with the associated identified bus.

Questions

1. Do you agree with the revisions to Requirement 1?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with including the implementation plan information in proposed Requirement R13?

   ☐ Yes
   ☐ No

   Comments:

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002-3

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. Each requirement is assigned a VRF and a VSL. 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 in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

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.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect 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

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs 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 VRF 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.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

PRC-002-4

VRF Justification for PRC-002-4, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
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 that their BES Elements require SER or FR data by 10 calendar days or less. OR	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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

The Transmission Owner as directed by Requirement R1, Part 1.2 did not notify the other owners that their BES Elements do not require SER or FR data within 90 calendar days.			

VSL Justifications for PRC-002-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less). Consistent with the proposed revisions to the associated requirement, the SDT also added langue to the Lower VSL to address the instance where the Transmission Owner as directed by Requirement R1, Part 1.2 did not notify the other owners that their BES Elements do not require SER or FR data within 90 calendar days.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do 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	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-002-4, Requirement R1	
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	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-4, Requirement R2
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R2
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R3
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R3
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R4
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R4
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 did not notify the owners that their BES Elements do not require DDR data within 90 calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

VSL Justifications for PRC-002-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less). Consistent with the proposed revisions to the associated requirement, the SDT also added languge to the Lower VSL to address the instance where the Reliability Coordinator as directed by Requirement R5, Part 5.3 did not notify the owners that their BES Elements do not require DDR data within 90 calendar days.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do 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 VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative	Each VSL is based on a single violation and not cumulative violations.

VSL Justifications for PRC-002-4, Requirement R5	
Number of Violations	

VRF Justification for PRC-002-4, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R6
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R7
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R7
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R8
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R8
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R9
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R9
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R10
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R10
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R11

The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R11

The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R12

The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R12

The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justifications for PRC-002-4, Requirement R13	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R13 is consistent with those of other requirements to have DDR, SER, or FR data in the proposed Reliability Standard.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-002-4, Requirement R13			
Lower	**Moderate**	**High**	**Severe**
The Transmission Owner or Generator Owner had SER data for more than 75 percent, but less than 100 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for more than 75 percent, but less than 100 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for more than 75 percent, but less than 100 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.	Transmission Owner or Generator Owner had SER data for more than 50 percent, but less than 75 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for more than 50 percent, but less than or equal to 75 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for more than 50 percent, but less than or equal to 75 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.	The Transmission Owner or Generator Owner had SER data for more than 25 percent, but less than 50 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for more than 25 percent, but less than or equal to 50 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for more than 25 percent, but less than or equal to 50 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.	The Transmission Owner or Generator Owner had SER data for less than or equal to 25 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had FR data for less than or equal to 25 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3. OR The Transmission Owner or Generator Owner had DDR data for less than or equal to 25 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4

VSL Justifications for PRC-002-4, Requirement R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.

VSL Justifications for PRC-002-4, Requirement R13	
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	The proposed VSLs are not binary and do 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 VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

Technical Rationale for Reliability Standard PRC-002-4

April 2022

PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator 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 Requirement 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-002-4, 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.

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.
5. 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.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners are notified. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 1 and 2 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

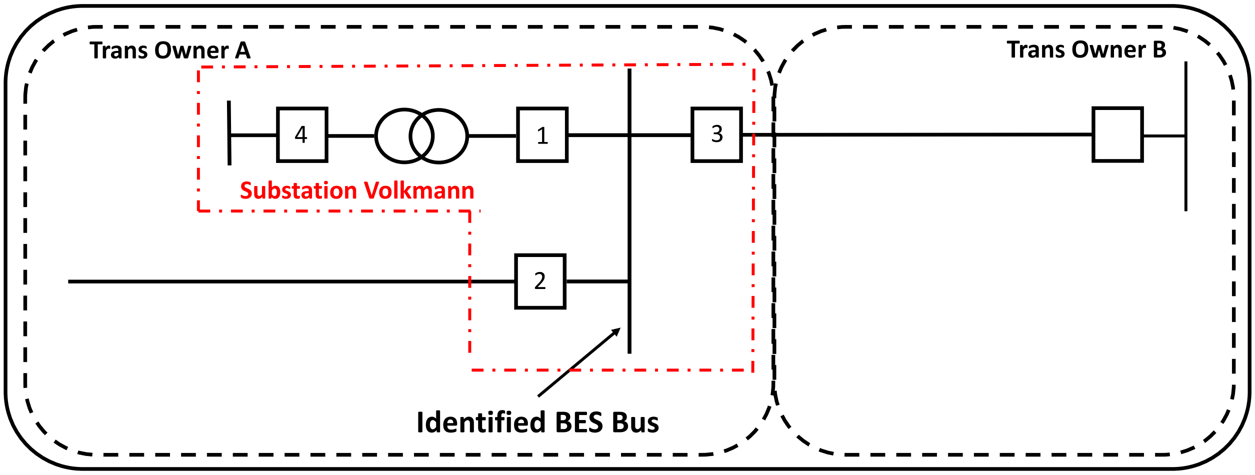

Figure 1: Straight Bus Configuration – Single Owner

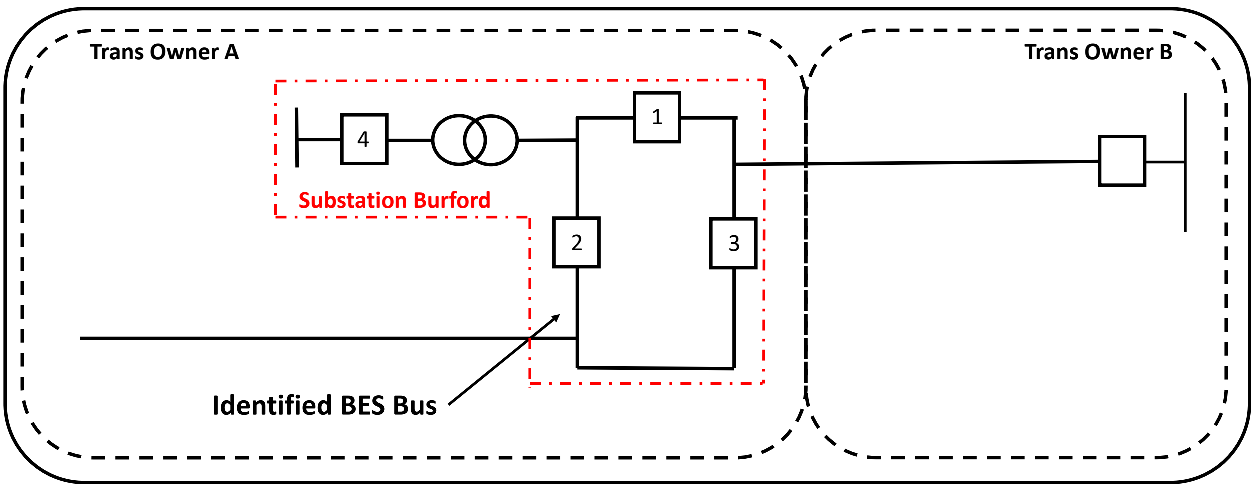

Figure 2: Ring Bus Configuration – Single Owner

Figures 3 and 4 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified of their responsibility to record SER/FR data for circuit breaker 3.

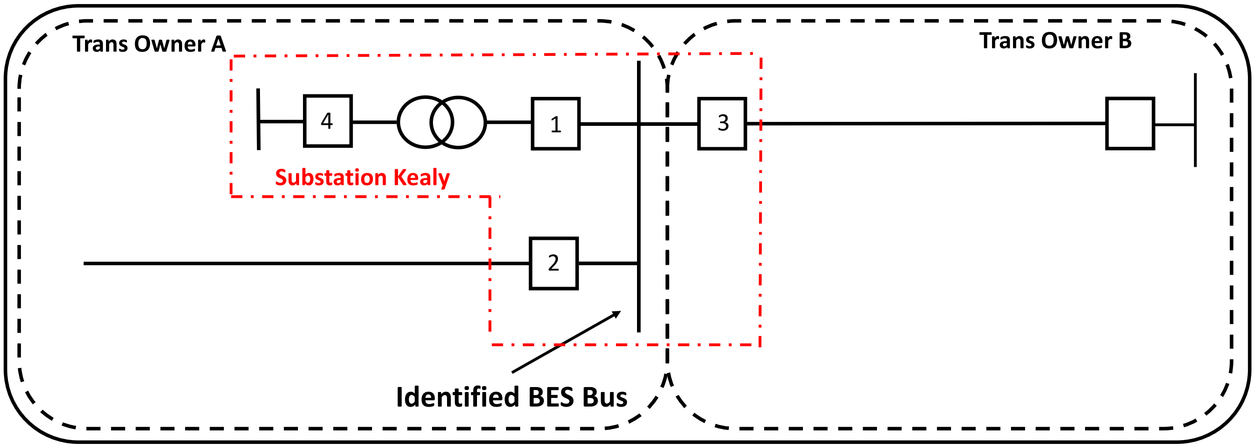

Figure 3: Straight Bus Configuration – Multiple Owners

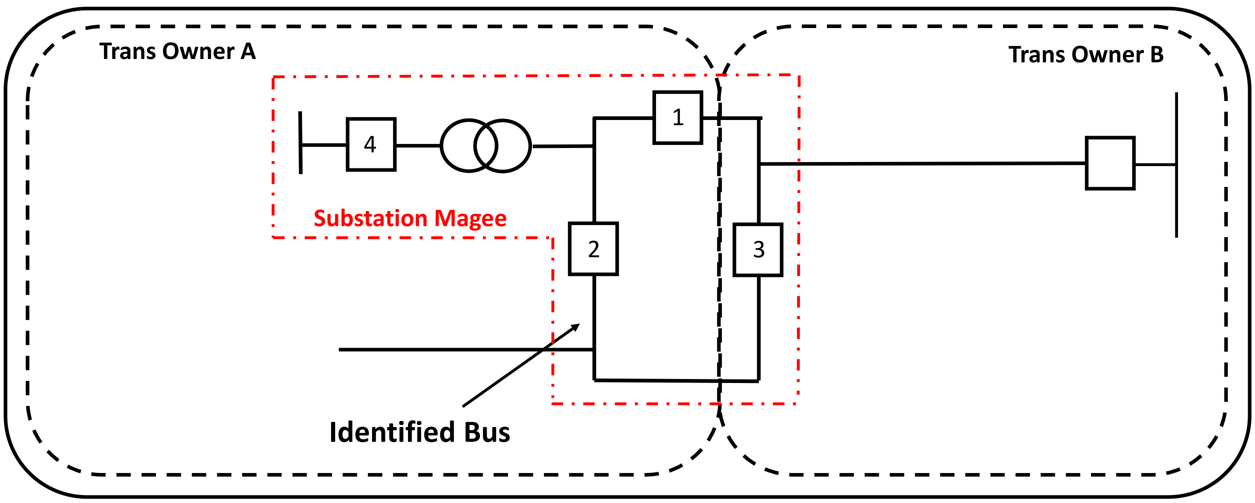

Figure 4: Ring Bus Configuration – Multiple Owners

Figure 5 shows an example with a generator interconnection. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified of their responsibility to record SER data for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

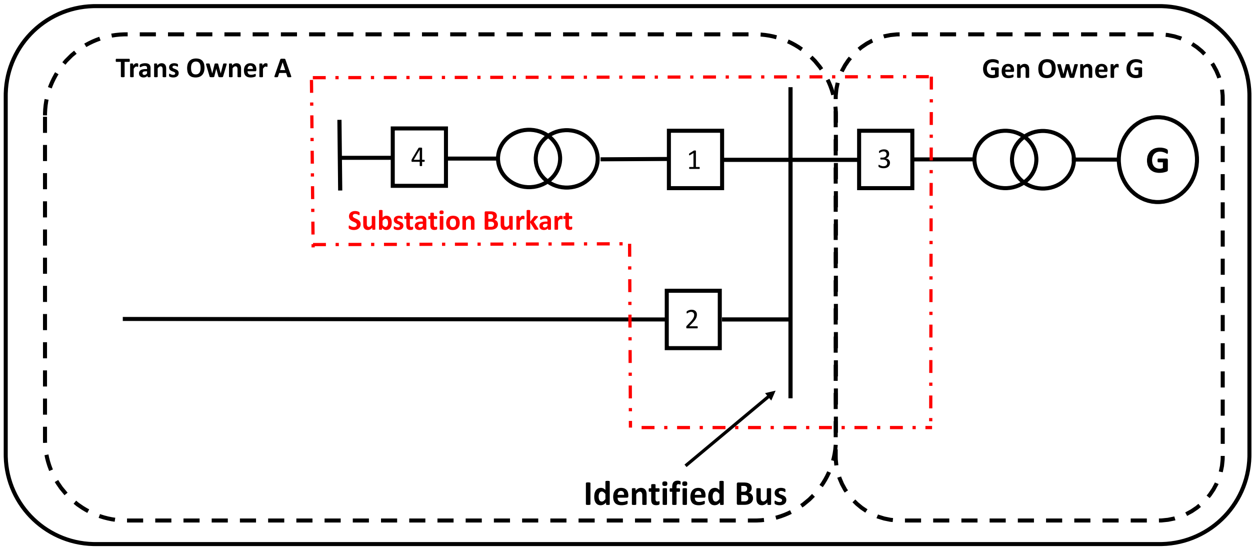

Figure 5: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 6, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

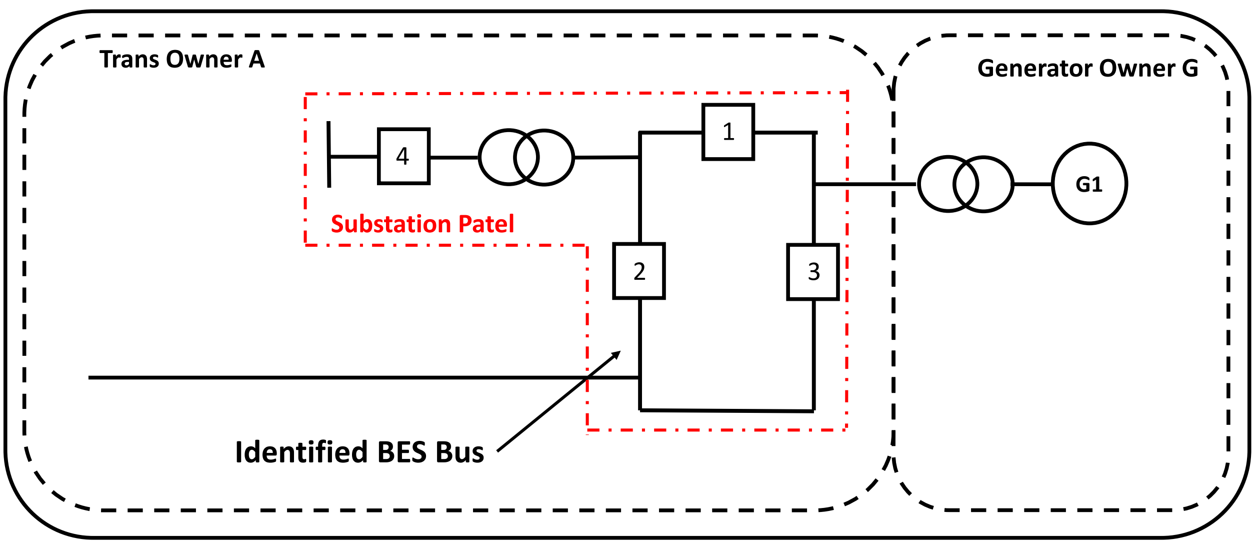

Figure 6: Generator Interconnection to Ring Bus

Figure 7 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified of their responsibility to record SER data for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

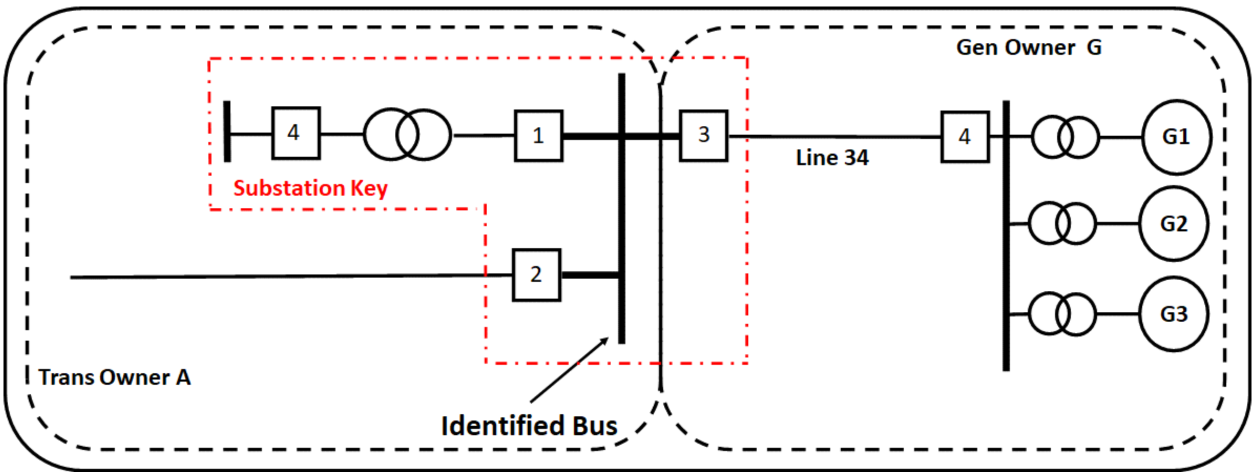

Figure 7: Generator Interconnection via Line 34

Figure 8 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. Due to the loop created by Line 36 and Line 57, FR data is required for these lines and SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breakers 3 and 5, then Generator Owner G must be notified of their responsibility to record SER and FR data for circuit breakers 3 and 5.

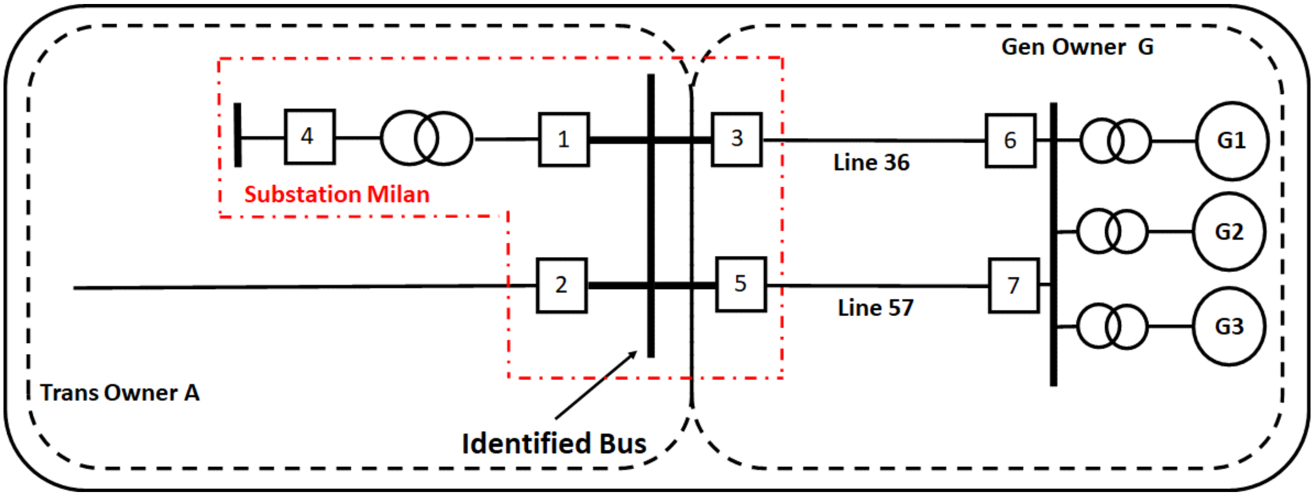

Figure 8: Generator Interconnection via Multiple Lines

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.

Rationale for Requirement 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 and 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.

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.

Rationale for Requirement 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.

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.

<u>Voltage Recordings</u>
Voltages are to be recorded or accurately determined at applicable BES buses

Rationale for Requirement 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.

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.

Rationale for Requirement 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 Reliability Coordinator 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 Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator 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 Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator 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 Reliability Coordinators, each Reliability Coordinator 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 Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator 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 Reliability Coordinators. It is intended that each Reliability Coordinator 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.

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 Reliability Coordinator 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 Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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.).

Rationale for Requirement 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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

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 Reliability Coordinator 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-002-4 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.

Rationale for Requirement 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.

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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement 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).

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.

Rationale for Requirement 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.

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.

Rationale for Requirement 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.

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.

Rationale for Requirement 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. A10-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.

This requirement directs the applicable entities, upon requests from the Reliability 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 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 synchrophasor 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.

Rationale for Requirement 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.

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.

Rationale for Requirement R13

Three (3) calendar years following a notification by the Transmission Owner or the Reliability Coordinator to another Transmission Owner/Generator Owner is the same amount of time provided in the Implementation Plan of previous versions of this NERC Reliability Standard. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years following a notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement

R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Standards Announcement

Project 2021-04 Modifications to PRC-002

Formal Comment Period Open through July 25, 2022
Ballot Pools Forming through July 8, 2022

Now Available

A formal comment period for **Project 2021-04 Modifications to PRC-002**, is open through **8 p.m. Eastern, Monday, July 25, 2022** for the following standard and implementation plan:

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements
- Implementation Plan

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Thursday, July 8, 2022.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the standard and implementation plan, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 15 - 25, 2022**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-04 Modifications to PRC-002” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2021-04 Modifications to PRC-002 | Draft 1
Comment Period Start Date:	6/9/2022
Comment Period End Date:	7/25/2022
Associated Ballots:	2021-04 Modifications to PRC-002 | Draft 1 Implementation Plan IN 1 OT 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 | Non-binding Poll IN 1 NB 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 IN 1 ST

There were 67 sets of responses, including comments from approximately 152 different people from approximately 98 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the revisions to Requirement 1?

2. Do you agree with including the implementation plan information in proposed Requirement R13?

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	SRC 2022	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Matt Goldberg	ISONE	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
James Mearns	James Mearns			NCPA HQ	Jeremy Lawson	Northern California Power Agency	5	WECC
					Marty Hostler	Northern California Power Agency	4	WECC
					Dennis Sismaet	Northern California Power Agency	6	WECC
					Michael Whitney	Northern California Power Agency	3	WECC
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC

					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Patricia Ireland	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO

					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
LaKenya VanNorman	LaKenya VanNorman		SERC	Florida Municipal Power Agency (FMPA) and Members	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
					Don Cuevas	Beaches Energy Services	1	SERC
					Carolyn Woodard	Beaches Energy Services	3	SERC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC

					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC

					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

1. Do you agree with the revisions to Requirement 1?	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
1) Manitoba Hydro is unclear on the intent of the changes made to R1, which requires SER and FR data for the remote end? 2) For clarity, Manitoba Hydro recommends that the sentance: "Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days." be reworded to read "Notify other owners of BES Elements directly connected to those BES buses, for which the Transmission Owner does not record SER or FR data that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days."	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
The meaning and importance of the SDT's intentional addition of the word "directly" to R3 is unclear. Please consider providing a robust technical definition, additional clarification, and/or example(s) from a compliance perspective regarding the importance of adding the word "directly" as stated in R3.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro thanks the drafting team for their efforts and offers the following comments and suggestions.

The revised wording of Requirement R1 Part 1.2 references responsibilities for recording the SER or FR data while the revised Requirement R1 Part 1.3 mandates that the Transmission Owner (TO) notify other owners of their responsibilities. These revisions could be interpreted as an obligation of the TO to educate other utilities regarding their responsibilities. BC Hydro's understanding, in line with the verbal drafting team's clarifications during the July 6, 2022 industry webinar, is that to meet the intent of Requirement R1 (including Part 1.3) the TO is only required to provide notification to other owners of BES Elements subject to PRC-002 once this identification was made in accordance with Part 1.1. Also, the notification required in Part 1.3 is necessary only for newly identified BES Elements, or BES Elements that no longer require to have SER of FR data recorded. Please confirm whether this understanding is accurate.

BC Hydro recommends that the Requirement R1 Part 1.3 be revised to remove the "of their responsibilities" wording. Below is suggested wording for Requirement R1 Part 1.3.

"**1.3** Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners in accordance with Part 1.2."

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP would like to express its overall support of the first phase of Project 2021-04. Our negative votes in this ballot period are in response *only* to our objections stated below that the illustrative examples are provided outside of the standard within in the Technical Rationale document, rather than embedded within the standard itself.

Technical Rationale documents are to assist in the technical understanding of a requirement and/or Reliability Standard, and are not to include compliance examples or compliance language. That being said, the examples provided in the proposed Technical Rationale document on pages 4 through 9 appear to go beyond mere "technical understanding" of the obligations and could possibly be referred to in determination of compliance of those obligations. As such, we believe it would be more appropriate for this content to be embedded within the standard itself, perhaps as an "Attachment 3."

Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment

Instead of making the Transmission Owner state in their notification that another owner is responsible for SER and/or FR data, PRC-002 should clearly state compliance responsibilities for all entities. BPA suggests R1 be restructured to clearly state what information the notifications shall contain. R1 should also state owner responsibilities in the event that a notification is received from another owner that SER and/or FR data is not being recorded by the Transmission Owner who identified the BES bus. This allows for compliance responsibility to be stated in the standard rather than have Transmission Owners mandate compliance responsibilities to other BES element owners. If the Transmission Owner does not have any BES Elements that do not have SER and/or FR data per PRC-002-4, BPA feels the notifications to other owners is still valuable to ensure PRC-002 compliance has been communicated to all other owners. BPA realizes this suggested change also impacts the changes to PRC-002-4 Technical Rationale. However, if notifications are needed regardless of whether or not another owner requires SER and/or FR data, the provided examples in the PRC-002-4 Technical Rationale for R1 may not be needed.

Suggested R1 changes are as follows:

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-002-4, Attachment 1.

1.2. Notify other owners of their BES Elements connected directly to those BES buses *identified in Part 1.1. This notification shall:*

1.2.1 *Be sent within 90 calendar days of completion of Part 1.1.*

1.2.2 *Include identified BES Elements where the Transmission Owner has SER and/or FR data that meet the requirements of PRC-002-4.*

1.2.3 *Include identified BES Elements where the Transmission Owner does not have SER and/or FR data and will require SER and/or FR data monitoring from the connected owner to meet the requirements of PRC-002-4.*

1.2.4 *Include identified BES Elements, if any, that were removed from the BES bus list identified in Part 1.1 and no longer require SER and/or FR data to meet the requirements of PRC-002-4.*

1.3. *Review notifications received under Part 1.2 to ensure BES Elements identified under Part 1.2.3 meet the requirements of PRC-002-4.*

1.4. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners *in accordance with Part 1.2.*

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	

Comment

The MRO NSRF agrees with revising R1 to clarify the notification and responsibility for FR/SER data. These revisions will reduce the compliance evidence scope for storing notifications that do not require the recipient owner to take action.

The examples in the Technical Rationale document for Figures 1-8 are helpful. We request the team consider providing some example diagrams or clarification to further define “directly connected” for 1) how a center breaker is addressed on a breaker and a half configuration since these breakers do not appear to be “directly” connected to a bus, 2) how a line connected shunt reactor breaker is addressed that is inside the substation boundary but on the line side of two ring or breaker and a half breakers.	
Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation supports the attempt to clarify R1 but recommends additional clarity is needed regarding the scope of BES Elements in R1.2. According to Attachment 1, each TO is responsible to evaluate equipment it owns. R1.2 brings in other owners, so it seems obvious that one TO would not be responsible for recording SER or FR data on another owner’s equipment, yet the TO is required to notify the other owner of this. Reclamation recommends R1.2 be reworded to clarify the notification goes to “owners of other BES Elements…”. Reclamation recommends removing the proposed last sentence of R1.2 (“If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days.”) A compliance obligation to perform this notification does not impact reliability and has no value.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF comments: The MRO NSRF agrees with revising R1 to clarify the notification and responsibility for FR/SER data. These revisions will reduce the compliance evidence scope for storing notifications that do not require the recipient owner to take action. The examples in the Technical Rationale document for Figures 1-8 are helpful. We request the team consider providing some example diagrams or clarification to further define “directly connected” for 1) how a center breaker is addressed on a breaker and a half configuration since these breakers do not appear to be “directly” connected to a bus, 2) how a line connected shunt reactor breaker is addressed that is inside the substation boundary but on the line side of two ring or breaker and a half breakers.	
Likes 0	

Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
The language as proposed in R1 Part 1.2 and 1.3 needs to be clarified to remove the interpretion that obligaties/mandates the TO to set responsibilities of other utilites.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) appreciates the opportunity to respond and thanks the drafting team for their efforts. While the changes to R1 do not directly impact SIGE's procedures, SIGE recognizes the potential that the revisions may be burdensome on industrial customers and municipalities that may not readily have access to SER or FR data at the time of notification.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS supports the revisions to Requirement 1 in principal but recommends that the STD incorporate the revised language, suggested in EEI's submittal of comments, to clarify the language within R1, subpart 1.3 to the following:

"Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, **if the BES buses for which sequence of events recording (SER) and fault recording (FR) data is required has changed,** then notify other owners of their responsibilities **as it relates to the affected** BES Elements, in accordance with Part 1.2."

Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	

The language as proposed in R1 Part 1.2 and 1.3 needs to be clarified to remove the interpretation that obligates/mandates the Transmission Owner to set responsibilities of other utilities.

Please see BPA's suggested edits.

Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC (CEHE) recommends the following revisions to part 1.2 for clarity.

1.2 Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that *the other owner* is responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the *other* owner of a BES Element is no longer required to have SER or FR data, notify the *other* owner within 90 calendar days.

CEHE recommends that Part 1.3 include a reference to the implementation language that has been moved from the implementation plan to R13.

1.3 Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners of their responsibilities in accordance with Part 1.2 *and implement the re-evaluated list of BES buses as per Requirement R13 Part 13.1.*

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

MPC supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 6, 5; Jennifer Flandermeyer, Evergy, 1, 3, 6, 5; Jeremy Harris, Evergy, 1, 3, 6, 5; Marcus Moor, Evergy, 1, 3, 6, 5; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the response of the Edison Electric Institute (EEI) to questions #1.

Likes 0	
Dislikes 0	

Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	

Oncor appreciates the opportunity to respond and thanks the drafting team for their efforts. Oncor supports comments provided by CenterPoint Energy Houston Electric, LLC (CEHE) as follows:

1.2. Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that *the other owner* is responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the *other* owner of a BES Element is no longer required to have SER or FR data, notify the *other* owner within 90 calendar days.

CEHE recommends that Part 1.3 include a reference to the implementation language that has been moved from the implementation plan to R13.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners of their responsibilities in accordance with Part 1.2 *and implement the re-evaluated list of BES buses as per Requirement R13 Part 13.1.*

Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	

See Comments Submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon concurs with the clarification suggested in the EEI comment.

On behalf of Exelon, Segments 1 & 3

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

The language within R1, subpart 1.3 should be clarified and we offer the following:

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, **if the BES buses for which sequence of events recording (SER) and fault recording (FR) data is required has changed,** then notify other owners of their responsibilities **as it relates to the affected** BES Elements, in accordance with Part 1.2.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE abstains.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA) and Members

Answer	No

Document Name	
Comment	

The SAR from Glencoe noticeably identifies two issues. The proposed standard revision addresses only one of those issues (and we believe, insufficiently). The original SAR (Before SDT added some items to the list) identifies the following two issues:

1) R1.2 infers all owners of BES Elements connected to the identified buses should provide SER and FR data, regardless of what type of Element they own, while R3 clearly identifies that FR data is only required for two categories of Elements – Transformers with low side operating voltage of 100kV or above and Transmission lines. This means that entities that own transformers with a low side operating voltage below 100kV are not required to provide FR data but are being sent notifications per R1.2 with the implication they must provide it. The proposed standard revisions do nothing to clear up this issue.

2) Since all owners, whether joint or sole, of every BES Element connected to the identified bus or buses, are being notified, many owners are being notified but are not in a position to capture data that is consistent with the intent of the standard. Specifically, it is quite common for ownership to change along the length of a transmission line, often many miles away from the bus that was identified in R1.1. As such, the “remote joint owner” of the BES Element has no equipment within the substation fence of the bus that was identified and is not in any position to capture any data relative to the identified bus, since it has no measurement equipment in that location. It was clearly not the original intent of the standard to require that every element connected to an identified bus have measurements at both ends (remote and local). We believe the intent of the original standard was clear that when a bus is identified, measurements obtained would be at the local bus location (whether terminal flows or bus voltages, they would be at that bus location). Modifying the language in R1.2 and R3 to include “directly connected” unfortunately does not fix the clear overreach that many auditors have inferred. If a transmission line is “jointly owned”, they consider it the responsibility of both owners to obtain the FR and SER data, even though in most cases the “joint” owner takes over ownership at the remote end of the line.

In order to fully address the original SAR (as we read it), the standard should be revised to make it clear only owners of equipment local (again, Directly Connected doesn’t help since the term BES Element has no fractional ownership in its definition) to the substation bus identified have the obligation to record data, and it should be clarified that only those entities that own BES Elements listed in R3.2 must provide FR data regardless of receipt of a notification. Ideally no notification would be required but SER data coverage must also be considered, since today both are performed with one notification.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

Clarification is required with respect to required notifications. Suggestion is made to include in Appendix 1 the BES Elements exclusion of the Transformers that have a low-side operating voltage below 100kV. This will eliminate the unnecessary notification of BES Element Owners in accordance to R1, only to exclude it afterwards as per R3, Part 3.2, sub 3.2.1.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 5 - WECC	
Answer	No
Document Name	
Comment	

PacifiCorp agrees with revising R1 to clarify the notification and responsibility for FR/SER data. These revisions will reduce the compliance evidence scope for storing notifications that do not require the recipient owner to take action.

The examples in the Technical Rationale document for Figures 1-8 are helpful. We request the team consider providing some example diagrams or clarification to further define “directly connected” for 1) how a center breaker is addressed on a breaker and a half configuration since these breakers do not appear to be “directly” connected to a bus, 2) how a line connected shunt reactor breaker is addressed that is inside the substation boundary but on the line side of two ring or breaker and a half breakers.

Likes 0	
Dislikes 0	
Response	

Glenn Pressler - CPS Energy - 1,3,5	
Answer	No
Document Name	
Comment	

CPS Energy feels that 1.2 still needs work to make clear who is responsible for providing SER or FR data in stations where multi-owners are involved. When used in conjunction with the technical reference document (Technical Rationale), it is mostly fine, however, without the technical reference, the standard is not entirely clear who is responsible for busses with multi-owners. In the first sentence of 1.2, the sentence “for which the Transmission Owner does not record SER or FR data” really needs to be reworded to include “and is not responsible for recording SER or FR data” to notify the other owner(s) of the responsibility for recording the SER or FR data. However, need to remove a new requirement obligation of the studying entity, in R1 Part 1.2 and 1.3, to be required to assign requirement obligations to another entity; this needs to be fixed to remove the interpretation that obligates the Transmission Owner to set responsibilities of other entities.

Examples in standard would be preferred; the best solution is to provide complete clarity and add the technical reference with diagrams and explanations to the end of the standard, as is done in PRC-025-2, for example.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
WECC agrees with the idea and intent but believes the wording in 1.2 could be improved. 1) it states "Notify other owners of BES elements, for which the Transmission Owner does not record SER of FR data..." This could be confusing since the other "owner" could also be a Transmission Owner. 2) while recording of SER and FR data is one way of providing the data. Calculation of required data is also possible. So use of "recording" may be implying the need for equipment that is not explicitly specified by the standard. WECC recommends that the Drafting Team consider the following change in wording: "Notify other owners of BES elements, for which the Transmission Owner performing the assessment per Attachment 1 does not obtain SER or FR data, that the BES Element owners are responsible for providing the SER or FR data...."	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no proposed comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation has no proposed comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with these revisions. The R1 changes provide clarity that should reduce the number of unnecessary notifications made and received by each entity.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	

Comment	
NRG generally agrees with the revisions. The additions make the requirements clear regarding who has the obligations for installing SER or FR recorders. We are hesitant that the Transmission Owner is the party making the decision regarding whether it will be them or the Generator Owner to install the recorder. We would favor a third party, like an RC, to make the determination or to encourage discussions between the affected owners. NRG has had good experiences working with TOs to install recorders in the past and encourage discussions between the TO and GO regarding who should perform the installation.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FE suggest clarifying R1.3 to state "notify other owners of changes in their responsibilities". 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and **if necessary, notify** other owners **of changes in their responsibilities**, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan. The reason for this modification is that the "other owners" have been previously notified in Part 1.2 of their responsibility; so, the "other owners" should only be notified of changes to their responsibilities.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E supports the revisions to Requirement R1, but has the following input the SDT should consider for R1.2:	

R1.2 indicates for the Transmission Owner - "… If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days."

PG&E concern is the language does not address what happens if there are changes between the 5-year evaluation periods resulting in changes to the SER and FR data collection capabilities. There does not appear to be any requirement to communicate those changes so the owner either stops the work that is no longer required or starts work that would be required to maintain the reliability of the Bulk Electric System (BES).

PG&E recommends the SDT consider the above and determine how to address this condition to avoid work that is no longer required or could lead to reliability issues for work that should be done

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	Yes
Document Name	

Comment

Black Hills Corpoariton agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with the revisions to Requirement 1 however, proposes the following language for clarity: "Notify other owners of BES Elements directly connected to those BES buses, for which the Transmission Owner does not record SER or FR data that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days."	
Likes 0	
Dislikes 0	
Response	

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	Yes
Document Name	
Comment	
The suggested revisions to Requirement 1 are consistent with the principle that the TO/TP remain responsible for identification of locations requiring FR/SER/DDR capability.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy DeVries - CMS Energy - Consumers Energy Company - 1,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brendan Baszkiewicz - Eversource Energy - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn McAvoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Reinecke - Seminole Electric Cooperative, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed the term “owners” throughout the requirements. Texas RE recommends clarifying that “owners” refers to NERC-registered Transmission Owners or Generation Owners to eliminate the possibility that a non-NERC registered entity may be designated within a Facility that requires FR/SER data per a registered entity’s determination to ensure effective review of materials after an event.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no comments.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	
Document Name	
Comment	
SRC submits no response to this question.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with including the implementation plan information in proposed Requirement R13?

Glenn Pressler - CPS Energy - 1,3,5	
Answer	No
Document Name	
Comment	
Not necessarily against the 3-year term; would prefer calendar years or calendar months (e.g. 36 calendar months). Also, make clear that both Transmission Owner and other owners of BES elements notified per R1/R5 need to have the equipment installed in 3 years; same concern, 3-years from what; fix by specifying three calendar-years from date notified. Noted the Technical Rationale references “Three (3) calendar years.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 5 - WECC	
Answer	No
Document Name	
Comment	
PacifiCorp agrees with the need for including the re-evaluation and implementation plan as R13. It aligns with the prior implementation plan and will clearly carry forward newly applicable BES elements within the standard.	

We would like to request clarification for the meaning of the word “notification” in 13.1. For example, a TO performs the 5-year re-evaluation and they do not need to notify others and are not notified by others. In this case when would the 3-year timeline start?

The NSRF recommends the following revised language: “Within three (3) calendar years of notification under Requirement R1, Part 1.2, or completion of Requirement R1, Part 1.3, as applicable, have SER or FR data …”

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

Due to current Supply Chain challenges and based of Planned Outages Schedule interval of 3 years for nuclear generating units a suggestion is made that where the determination has been made that the DMEs are required to be installed, the implementation of the SER, FR, and DDR shall be the result of commonly agreed scheduled, negotiated between the TO and GO.

Likes 0	
Dislikes 0	

Response

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ

Answer	No
Document Name	

Comment

This approach seems inconsistent with the "effective date" approach identified in other NERC requirements with staged implementation dates and appears to dilute the effectiveness of the Implementation Plan concept.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE is concerned with the prescriptive nature of a three (3) year notification clock. Perhaps a reasonable Corrective Action Plan could be developed?	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
We agree with including the implementation plan information within proposed Requirement R13 but also suggest Part 13.1 and Part 13.2 be revised to state, "Within three (3) calendar-years…", instead of "Within three (3) years. Three calendar-years would be helpful for the installation of new equipment, since a calendar-year ends on December 31st vs. stating within (3) years which could be interpreted as three years from the notification date. The Technical Rationale references, "Three (3) calendar years…"	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the clarification suggested in the EEI comment. On behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See Comments Submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
In consideration of recent material shortages and supply chain disruptions, Oncor recommends an implementation period of 5 calendar years for Requirement 13 Part 13.1 and Part 13.2.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 6, 5; Jennifer Flandermeyer, Evergy, 1, 3, 6, 5; Jeremy Harris, Evergy, 1, 3, 6, 5; Marcus Moor, Evergy, 1, 3, 6, 5; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the response of the Edison Electric Institute (EEI) to questions #2.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Northern Indiana Public Service Company supports the addition of Requirement R13, but recommends changing the period of time from "three year" to "three calendar year" to be consistant with other parts of the standard.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	No
Document Name	
Comment	
I'm concerned that 3 years may be insufficient to plan/design new SER/FR installations, procure equipment, and install the equipment, particularly for power plants (GO) where such installation should be coordinated with plant outage schedules in order to not adversely affect plant availability. The 3 year implementation time frame might be to constrictive especially in light of recent material shortages. Suggest a 7 year time frame would allow BES element owners time to work the project into their schedule and procure equipment and resources.	
Likes 0	
Dislikes 0	

Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC recommends an implementation period of 5 calendar years for Requirement 13 Part 13.1 and Part 13.2.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
We are concerned that 3 years may be insufficient to plan/design new SER/FR installations, procure equipment, and install the equipment, particularly for power plants (GO) where such installation should be coordinated with plant outage schedules in order to not adversely affect plant availability.	
Likes 0	
Dislikes 0	
Response	

Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Recommend a similar path that PRC-026 R3 and R4 takes: upon notification of the need to install a DDR (from R5) create a corrective action plan and implement it.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS supports the inclusion of the implementation plan in proposed Requirement R13 but recommends that the STD incorporate the revised language, suggested in EEI's submittal of comments, to clarify the language within R12, subparts 13.1 and 13.2 to the following: "Within three (3) calendar-years…", instead of "Within three (3) years. Three calendar-years would be helpful for the installation of new equipment, since a calendar-year ends on December 31st vs. stating within (3) years which could be interpreted as three years from the notification date. The Technical Rationale references, "Three (3) calendar years…"	
Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3 - RF	
Answer	No
Document Name	
Comment	
SIGE recommends the implementation period be amended from "three (3) years" to "five (5) calendar years". The addition of "calendar" is to mirror the language in R1. SIGE believes the three-year implementation period may be too restrictive given set project cycles and several challenges faced by the industry including outage constraints due to capacity shortfalls and long lead-times due to supply chain issues.	

Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF comments: The MRO NSRF agrees with the need for including the re-evaluation and implementation plan as R13. It aligns with the prior implementation plan and will clearly carry forward newly applicable BES elements within the standard. We would like to request clarification for the meaning of the word "notification" in 13.1. For example, a TO performs the 5-year re-evaluation and they do not need to notify others and are not notified by others. In this case when would the 3-year timeline start? The NSRF recommends the following revised language: "Within three (3) calendar years of notification under Requirement R1, Part 1.2, or completion of Requirement R1, Part 1.3, as applicable, have SER or FR data …"	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
The "General Considerations" bullet in the implementation plan pertaining to Requirement R13 is unclear. Reclamation recommends aligning R13 with the five-year requirement to avoid the potential for entities to be placed in a constant state of review.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No

Document Name	
Comment	

The MRO NSRF agrees with the need for including the re-evaluation and implementation plan as R13. It aligns with the prior implementation plan and will clearly carry forward newly applicable BES elements within the standard.

We would like to request clarification for the meaning of the word “notification” in 13.1. For example, a TO performs the 5-year re-evaluation and they do not need to notify others and are not notified by others. In this case when would the 3-year timeline start?

The NSRF recommends the following revised language: “Within three (3) calendar years of notification under Requirement R1, Part 1.2, or completion of Requirement R1, Part 1.3, as applicable, have SER or FR data …”

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	No
Document Name	
Comment	

While AEP acknowledges that the existing Implementation Plan for the standard under enforcement has a “three year” period of time to have data in response to notification(s) under R1, we recommend changing this to “three calendar years” under the proposed R13.

Likes 0	
Dislikes 0	
Response	

Scott Kinney - Avista - Avista Corporation - 3

Answer	No
Document Name	
Comment	

R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.

Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Suggest implementation period be amended from 3-years to 4-years. The requirement for a 3-yr compliance period will conflict with previously scheduled and planned outage/maintenance/fueling cycles since: (a) the ability to install equipment is significantly affected by outage constraints, equipment lead-times and availability and, (b) the Covid pandemic has significantly impacted supply chain and availability of work resources. Overall, the 3-year window creates a condition whereby an entity must fast-track the installation of monitoring equipment over other work which better supports grid stability. Additionally, the 3-year implementation period is especially disadvantageous to nuclear sites with 2-year refueling cycles/outages.	
Likes 0	
Dislikes 0	
Response	
Wendy DeVries - CMS Energy - Consumers Energy Company - 1,5 - RF	
Answer	No
Document Name	
Comment	
The 3 year implementation time frame might be to constrictive especially in light of recent material shortages. Suggest a 7 year time frame would allow BES element owners time to work the project into their schedule and procure equipment and resources.	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with moving the three year notification requirement from the implementation plan directly to the standard to provide more clarity.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF has no comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	Yes
Document Name	

Comment

Black Hills Corpoariton agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	Yes
Document Name	

Comment	
PG&E supports the proposed Requirement R13, but has the following question and recommendation: Does the three-year implementation trigger start on the day that the affected BES Element owner is informed of their new SER, FR, and/or DDR data obligation(s). The current Requirement language is not clear on the trigger start. PG&E recommends this be clearly indicated to avoid interpretation differences between the Registered Entity and Regional Entity	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Yes, but consider stating three calendar years as noted by APS.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with including the implementation plan information in the proposed Requirement R13, however believes additional clarity should be provided. Proposed language indicates a 3-year implementation plan upon receipt of notification in R1.3, however a 3-year implementation should also be included for the entity performing the reevaluation and identifies their own buses in R1.1. This seems implied but should be explicit.	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
No comment at this time.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed Requirement R13, however, recommends the replacement of "within three (3) years of notification" to three (3) calendar years of notification. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation agrees with the proposed Requirement R13, however, recommends the replacement of "within three (3) years of notification" to three (3) calendar years of notification.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	

Since the term Calendar Year is used in Parts 1.3 and 5.4, WECC recommends that the Drafting Team consider replacing the words "Three (3) years" with the words "36 months." This would provide more clarity than using two different meanings of the term "year" within the same standard and would be consistent with other terminology in the standard.

Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

Manitoba Hydro proposes that language in sections 13.1. and 13.2. be revised to read:

13.1. Within three (3) years of **receiving** notification under Requirement R1, Part**s 1.2 and** 1.3, have SER or FR data as applicable for BES Elements directly connected to BES buses identified during the re-evaluation.

13.2. Within three (3) years of **receiving** notification under Requirement R5, Part**s 5.3 and** 5.4, have DDR data for BES Elements identified during the re-evaluation.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA) and Members

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Reinecke - Seminole Electric Cooperative, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn McAvoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brendan Baszkiewicz - Eversource Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	
Document Name	
Comment	
SRC submits no response to this question.	

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT noticed that the Implementation Plan for PRC-002-4 states, "The elements of the Implementation Plan for PRC-002-3 are incorporated herein by reference and shall remain applicable to PRC-002-4." And the Implementation Plan for PRC-002-3 contains the following language:

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.

Thus, the three-year compliance window for BES Elements added pursuant to a re-evaluation in R1 or R5 exists pursuant to the Implementation Plan, although the SAR expressed desire to remove this compliance window from the Implementation Plan. In this case, R13 should be removed.

If the compliance window is removed from the Implementation Plan, ERCOT notes that the proposed R13 language does not fully address the compliance-window issue. R13 provides a compliance window, but does not tie the window specifically to the applicable data requirements, such as R2. Each data requirement may need to reference R13 or the SDT may want to consider putting the three-year compliance window language within each requirement rather than as a stand-alone requirement.

Regardless of where the implementation window lies, the language should be clear that the three-year compliance window only applies to *new BES Elements*, not all BES Elements, identified pursuant to the R1 and R5 review cycle.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE appreciates the SDT addressing Texas RE's concern and moving the periodic requirements associated with R1 and R5 away from the Implementation Plan and into Requirement R13.

Texas RE recommends stating specifically which elements from the PRC-002-3 Implementation Plan are incorporated into the PRC-002-4 Implementation Plan. The PRC-002-4 Implementation Plan contains the phrase: "the elements of the Implementation Plan for PRC-002-3 are incorporated herein by reference and shall remain applicable to PRC-002-4". It is not clear which elements are incorporated by reference. The PRC-

002-3 Implementation Plan, it states, “unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4, PRC002-2, PRC-023-4, and PRC-026-1 are incorp orated herein by reference and shall remain applicable to FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2.” It is unclear which is carried through to the proposed PRC-002-4 Implementation Plan as there is no section in either Implementation Plan labeled as “elements”.

Likes 0	
Dislikes 0	

Response

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

Wendy DeVries - CMS Energy - Consumers Energy Company - 1,5 - RF	
Answer	
Document Name	
Comment	
The implementation time frame of 3 years isn't long enough for a BES element owner to gather bids, procure materials, and schedule the work, and then install the equipment. Time frame should be extended to 7 years if not that at least, 5 years.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
Manitoba Hydro proposes that language for requirement R3 be updated to read “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 **that are directly** connected to the BES buses identified in Requirement R1".	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
While R13 will have specified implementation times, the Violation Severity Levels for R13 do not address any severity with respect to the time specified for implementation in R13 as they do for R1 and R5. Is this intentional?	
Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP thanks the Standards Drafting Team for their efforts, and for pursuing AEP's previous recommendation for the two proposed SARs to each be dealt with in separate project phases.	
Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

R13 should apply to all of R1 and R5 and not just R1.3 or R5.4. SER and/or FR data should be required within 3 years whether an applicable BES Element is identified during the Transmission/Generator Owner's re-evaluation or if a BES Element is identified per receipt of a notification from another owner per R1.2 (specifically R1.2.3 if BPA's suggested changes to R1 are accepted).

The 15% margin proposed in Attachment 1, Step 7 seems very arbitrary and doesn't seem to provide any added reliability value other than making the logistics of having to add SER or FR equipment less burdensome. Unless there is proof that a 15% margin does not adversely impact reliability of the grid, the margin should not be added.

Overall:

- The Standard should not rely on other TO/GO's to mandate requirements on other TO/GO's.
- The Standard should define what information is required in the notifications.
- All Requirements within the Standard should have a foundation in improving or maintaining reliability of the transmission system.

Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

No additional comments.

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	

The proposed change to Attachment 1 Step 7 allows the possibility of significant change over time without a required change in data recording location. Reclamation recommends each re-evaluated three phase short circuit MVA be compared to the originally evaluated three phase short circuit MVA and no change is required only if the re-evaluated measurement is within 15% of the original measurement. Comparing each re-evaluated measurement to its previous measurement would allow no change in location in perpetuity so long as the difference changed by no more than 15% each re-evaluation, even if the net change over time was ultimately more than 15%.

In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1 and Requirements R1 and R5 should be revised to include Planning Coordinators.

Reclamation recommends removing the proposed last sentence of R5.3 (“If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days.”) A compliance obligation to perform this notification does not impact reliability and has no value.

To clarify that in the case of multiple RCs, each RC is responsible for its own RC Area (reference NERC Glossary of Terms “Reliability Coordinator Area”), Reclamation recommends changing the language in R5.4 as follows:

From:

Re-evaluate all BES Elements under its purview at least once every five calendar years…

To:

Re-evaluate all BES Elements in its Reliability Coordinator Area at least once every five calendar years…

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	

Document Name	
Comment	

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	
Comment	

No additional comments.

Likes 0	
Dislikes 0	
Response	

Deanna Carlson - Cowlitz County PUD - 5

Answer	
Document Name	
Comment	

No comment at this time

Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	

Agree with BPA comments.

Likes 0	
Dislikes 0	

Response

Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	
Consider the current uncertainty of supply chain issues and availability of parts.	
Likes 0	
Dislikes 0	
Response	

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	
Comment	
The implementation time frame of 3 years isn't long enough for a BES element owner to gather bids, procure materials, and schedule the work, and then install the equipment. Time frame should be extended to 7 years if not that, at least 5 years.	
Likes 0	
Dislikes 0	
Response	

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No additional comments.	

Likes 0	
Dislikes 0	

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	
Document Name	

Comment

The implementation time frame of 3 years isn't long enough for a BES element owner to gather bids, procure materials, and schedule the work, and then install the equipment. Time frame should be extended to 7 years if not that, at least 5 years.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

For R1.3, if the other owner is recording as notified per R1.2 and the 5-year re-evaluation per R1 indicates they are to continue to record, is a re-notification needed? Would this change the evidence retention for R1?

If FE's propose change in question 1 is accepted, should the Evidence Retention be revised in section B. Compliance, Part 1.2 to extend past 5 years if necessary to capture the last notification? Revision we suggest:

From:

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

To:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years or since the last notification in Part 1.2 or 1.3

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	
Comment	

Ameren agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

In R5, Part 5.3, a new requirement was added for the RC to notify appropriate entities if a BES Element is no longer required to provide DDR data. This goes beyond the scope of the SAR; although the RC may notify parties when certain data is not needed, there is no reliability need or benefit for making this notification a requirement. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. Since R 5.4 requires this to be evaluated every five years, there is no need to further obligate the RC to notify when DDR data is not needed. Therefore, the language, “If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days” should be stricken.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E has input on R5.3 which is the same as our comment and recommendation in Question 1 regarding R1.2. Please see our input for Question 1; the only difference is that R5.3 is related to the Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee

Answer	
Document Name	

Comment

Delete the word “for” from the title of the IEEE C37.111 standard title. The correct name is (IEEE Standard Common Format for Transient Data Exchange (COMTRADE).

VSL Table R11, change 11.1 to 11.2 in the sentence “The TO or GO as directed by R11, Part 11.1 provided the requested data more than x days” for all severity levels, as the Requirement for the requested data is R11.2 and not R11.1.

Technical Rationale: The standard addresses SER, FR, and DDR data, therefore, consider removing the last sentence of the Technical Rationale, Page 4, the first paragraph after the bullets, that reads “As a result, this standard only requires DDR data”. Or clarifying the sentence for the requirements that require DDR data only.

Technical Rationale: Page 11, Rationale R4, 3rd paragraph: should “protection System” be “Protection System”?

Technical Rationale: Page 18, Rationale for R11, 2nd paragraph should read “Providing the data within 30 calendar days (or the granted extension time), subject to Part 11.1, allows for a reasonable time to collect the data and perform any necessary computations or formatting” should read “…subject to Part 11.2”, as the Requirement for the requested data is R11.2 and not R11.1.

Technical Rationale: Page 19, 3rd paragraph “Requirement R11, Part 11.1 specifies the maximum time frame of 30 calendar days to provide the data.” Should read “Requirement R11, Part 11.2 specifies …”

Technical Rationale: Page 19, 4th paragraph “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” should read “Requirement R11, Part 1.1 ….”

For added clarity: suggest adding straight and ring bus examples in the technical rationale (similar to examples in figures 3 and 4 on pg. 6) where CB 3 is owned by TO B while TO A as a BES bus owner records SER and FR data for CB 3. And explain whether notification is required or not.

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	
Document Name	
Comment	
In regards to R1.3 if a entity identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required through the assessment required in R1.1 what is the time-frame to get evidence and possibly install equipment?	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 6, 5; Jennifer Flandermeyer, Evergy, 1, 3, 6, 5; Jeremy Harris, Evergy, 1, 3, 6, 5; Marcus Moor, Evergy, 1, 3, 6, 5; - Alan Kloster	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the response of the Edison Electric Institute (EEI) to questions #3.	
Likes 0	
Dislikes 0	
Response	

David Reinecke - Seminole Electric Cooperative, Inc. - 6

Answer	
Document Name	
Comment	
In regards to R1.3 if an entity identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required through the assessment required in R1.1 what is the time-frame to get evidence and possibly install equipment?	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	

Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	
Document Name	
Comment	
See Comments Submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	
Document Name	
Comment	
In regards to R1.3 if an entity identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required through the assessment required in R1.1 what is the time-frame to get evidence and possibly install equipment?	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE is concerned that the Technical Rationale for Requirement R1 references BES short circuit data from 2013. The grid has had a significant change in the resource mix since 2013, with the ERCOT region adding 11,650 MW of solar since 2013. Texas RE understands inverter-based resources will be addressed in the next phase of this project, with the SAR submitted by the IBRTF. Especially considering past and recent events in Odessa and California, as detailed in the Odessa Disturbance Report issued May 2021 and Multiple Solar PV Disturbances in CAISO dated April 2022, Texas RE encourages the SDT to consider a requirement for generators to have fault recording devices.

Texas RE noticed in section B. Compliance 1.3 Compliance Monitoring and Enforcement Program the term “Spot Checking” should be “Spot Check”, “Compliance Violation Investigation” should be “Compliance Investigation”, “Self Reporting” should be “Self Reports” Texas RE recommends the SDT consider adding Self-Logging.

Attachment 1 Comments

Texas RE recommends clarifying which “list” is being referenced for each step. Texas RE has the following additional comments regarding clarifying the steps in Attachment 1.

Texas RE understands the methodology as follows: A list is created in Step 1. In Step 2 the list in Step 1 is reduced to 1500 MVA or greater (with zero buses meaning the process is complete). Step 3 reduces the list in Step 2 to the 11 buses with the maximum available calculated three-phase short circuit MVA.

Texas RE noticed Step 3 does not provide guidance for more than 11 BES buses (from list in Step 2) that have ***equal*** maximum available calculated three phase short circuit MVA. The attachment is assuming non-equal buses which many larger utilities may have within their footprint.

Texas RE recommends clarifying Step 5 to state the number should be 20% of the median or 120% of the median MVA level. As the language is currently drafted, it reads if the median level were 1500 MVA Step 5 result would be 300 MVA which would mean every bus in Step 2 would require FR and SER data. If in Step 2 you reduce the list to 1500 MVA or greater then Step 6 automatically includes every bus.

Step 2 explains to reduce the list of BES buses to 1500 MVA or greater. Step 4 explains to use the 20% median level determined in Step 5. If the 20% is 300 MVA, as per Texas RE’s example above, is it the SDT’s intent to look in this range?

Step 7 (where there are 1 or more but less than or equal to 11 BES buses) appears to possibly limit FR and SER data at “the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 2. In other words, if all buses (1 to a maximum of 11) have the same “highest maximum available calculated three phase short circuit MVA” is the Transmission Owner only required to select one (1) BES Bus? Even if they do not have the same “highest maximum available calculated three phase short circuit MVA”, is the intent to only have FR and SER data at one (1) BES bus?

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

The NAGF provides the following comments for consideration:

1. Draft #1 PRC-002-4:

a. Recommend deleting page 2 as there are no new terms defined.

b. R13.1 and R13.2 – Replace "Within three (3) years of notification…" with "Within three (3) calendar years of notification…".

2. Attachment 1, Step 7:

a. The proposed change to Attachment 1 Step 7 allows the possibility of significant change over time without a required change in data recording location. Recommend that each re-evaluated three phase short circuit MVA be compared to the originally evaluated three phase short circuit MVA and no change is required only if the re-evaluated measurement is within 15% of the original measurement.

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	

Exelon concurs with the clarification suggested in the EEI comment.

On behalf of Exelon, Segments 1 & 3

Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	

Comment	
ERCOT agrees with the SRC. In R5, Part 5.3, the SDT placed a new requirement on the RC to notify owners if a BES Element is no longer required to have DDR data. This goes beyond the scope of the SAR; there is no reliability need or benefit to this notification. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. The language, "If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days" should be stricken. Although not preferred, if the SDT retains the language regarding notification when DDR data is not required, ERCOT requests that the SDT add "of completing Part 5.1" at the end of the sentence: "If the owner of a BES Element is no longer required to have DDR data, notify the owner within ninety calendar days *of completing Part 5.1*."	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
Please consider aligning the format of PRC-002-4 into the most recent version of NERC Drafting Team Reference Manual Version 4, chapter 10. For example, documents such at the Implementation Guidance and Technical Rationale are both referenced in a Section G of this Reliability Standard, but the Reference Manual states these documents should be in Section E: Associated Documents. Additionally, the Compliance language in Section C does not appear to be the most up-to-date language. The most up-to-date language should be used in the revised Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	

DTE supports NAGF's comment.

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA) and Members

Answer	
Document Name	

Comment

It is not clear why the Glencoe Light SAR was drafted independently from the IRPTF SAR, when both were approved at the same time. Some degree of communication of the SDT's plan would be beneficial. Since the proposed changes here are administrative, while the IRPTF's changes are more technical, we believe the Glencoe SAR should not be rushed or pushed through before the IRPTF SAR changes, and if this is a needed change, we welcome details or an explanation if this is only being balloted to get industry input on this issue, but ultimately no new revision will be pushed through until both SARs are addressed.

There has been a widespread problem with R1 of this standard requiring far too many entities to be "notified", which has been an issue for many years. In some regions, only a notification has been required to "remote joint owners", which was an administrative inconvenience (notification was required but the remote joint owner was not required to do anything with that information and was not required to capture any data). In other regions, the "remote joint owner" has apparently been interpreted to be required to capture data – getting back to the inference that receiving a notification under R1.2 somehow conveyed compliance responsibility to the recipient of the notification. The way the standard is written is too complex for a simple issue. Substations have buses and terminal equipment. When we identify a bus, we want voltage measurements on the bus itself, SER on the breakers to the terminal equipment, and FR of the flows on the terminals at that bus location. You can't make measurements without owning PTs, CTs, and relaying or DFR equipment. We suggest that we stop sending notifications to entities who don't own equipment within the substation or who own terminal equipment that isn't required to capture data (as per R3), and let's stop requiring "double-ended" FR and SER data. The problem is using "BES

Element" without any clarification. That term has been interpreted to mean the "entire element", and not just the portion that makes up the terminal at the substation.	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee's comments.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1

Answer	
Document Name	

Comment

Please consider organizing the sections of PRC-002-4 into the normal organization for reliability standards: Section A - Introduction, Section B - Requirements and Measures, Section C - Compliance, Section D - Regional Variances, Section E - Associated Documents. Please see the Drafting Team Reference Manual.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 5 - WECC

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment

MISO supports comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC).

In R5, Part 5.3, a new requirement was added for the RC to notify appropriate entities if a BES Element is no longer required to provide DDR data. This goes beyond the scope of the SAR; although the RC may notify parties when certain data is not needed, there is no reliability need or benefit for making this notification a requirement. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. Since R 5.4 requires this to be evaluated every five years, there is no need to further obligate the RC to notify when DDR data is not needed. Therefore, the language, "If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days" should be stricken.

This recommendations aligns with scope of the Standards Efficiency Review (SER) Project as it seeks to reduce regulatory obligations that are not essential for reliability and reduce compliance burden.

- Overall SER Project Scope
    - Evaluate NERC Reliability Standards using a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard Requirements. Considering that many Reliability Standards have been mandatory and enforceable for 10+ years in North America, this project seeks to identify potential candidate **requirements that are not essential for reliability, could be simplified or consolidated, and could thereby reduce regulatory obligations and/or compliance burden**.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022

Answer	
Document Name	

Comment

In R5, Part 5.3, a new requirement was added for the RC to notify appropriate entities if a BES Element is no longer required to provide DDR data. This goes beyond the scope of the SAR; although the RC may notify parties when certain data is not needed, there is no reliability need or benefit for making this notification a requirement. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. Since R 5.4 requires this to be evaluated every five years, there is no need to further obligate the RC to notify when DDR data is not needed. Therefore, the language, "If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days" should be stricken.

Likes 0	
Dislikes 0	

Response

Glenn Pressler - CPS Energy - 1,3,5

Answer	
Document Name	

Comment	
Technical Reference Comments • “Due to the loop created by Line 36 and Line 57, FR data is required for these lines and SER data is required on circuit breakers 3 and 5” o Do not disagree that this should be recorded, but not clear from standard and Glossary of Terms that this is a requirement. The Transmission Line definition is fairly vague and neither the glossary of terms or this standard makes clear that a loop suddenly makes these lines transmission lines needing FR versus the example with the singular line. If these lines (36 & 57) were really short, we probably would have considered generator feeds versus lines. • Rationale for Requirement R2 o Would be helpful to have diagrams showing what breakers feeding elements need and do not need SER or a more detailed statement – for example: Reactor banks, Capacitor banks, Station Service feed at power plant, Reactors off Auto Tertiary windings, etc. The “and” in the standard is something to take notice • 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”. o Not sure if second sentence of this statement is true since for multiple generators you can only calculate the total of the generators and not each generator which the statement seems to imply • Rationale for Requirement R4 o One suggestion would be to point out the need to capture the final cycle of the fault as seen by the fault recorder which can require the need to capture when current/voltage elements drop-out and not just pick up (for longer faults)	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2021-04 Modifications to PRC-002 | Draft 1
Comment Period Start Date:	6/9/2022
Comment Period End Date:	7/25/2022
Associated Ballots:	2021-04 Modifications to PRC-002 | Draft 1 Implementation Plan IN 1 OT 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 | Non-binding Poll IN 1 NB 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 IN 1 ST

There were 67 sets of responses, including comments from approximately 152 different people from approximately 98 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can 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 of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Do you agree with the revisions to Requirement 1?

2. Do you agree with including the implementation plan information in proposed Requirement R13?

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	SRC 2022	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Matt Goldberg	ISONE	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
James Mearns	James Mearns			NCPA HQ	Jeremy Lawson	Northern California Power Agency	5	WECC

					Marty Hostler	Northern California Power Agency	4	WECC
					Dennis Sismaet	Northern California Power Agency	6	WECC
					Michael Whitney	Northern California Power Agency	3	WECC
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC

DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Patricia Ireland	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO

					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC

					Greg Cecil	Duke Energy	6	RF
LaKenya VanNorman	LaKenya VanNorman		SERC	Florida Municipal Power Agency (FMPA) and Members	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
					Don Cuevas	Beaches Energy Services	1	SERC
					Carolyn Woodard	Beaches Energy Services	3	SERC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF

					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC

					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated	1	NPCC

						Edison Co. of New York		
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC

					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

1. Do you agree with the revisions to Requirement 1?	
Nazra Gladu - Manitoba Hydro – 1	
Answer	No
Document Name	
Comment	
1) Manitoba Hydro is unclear on the intent of the changes made to R1, which requires SER and FR data for the remote end? 2) For clarity, Manitoba Hydro recommends that the sentance: "Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days." be reworded to read "Notify other owners of BES Elements directly connected to those BES buses, for which the Transmission Owner does not record SER or FR data that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days.”	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. No, this is the opposite of the intent of the SAR. Please see the definition of “directly connected”. Revisions were made for clarity	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

The meaning and importance of the SDT's intentional addition of the word "directly" to R3 is unclear. Please consider providing a robust technical definition, additional clarification, and/or example(s) from a compliance perspective regarding the importance of adding the word "directly" as stated in R3.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The drafting team defined "directly connected" and is included in footnote in R1, and multiple examples of bus configurations to illustrate the concept are presented in the Technical Rationale.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro thanks the drafting team for their efforts and offers the following comments and suggestions. The revised wording of Requirement R1 Part 1.2 references responsibilities for recording the SER or FR data while the revised Requirement R1 Part 1.3 mandates that the Transmission Owner (TO) notify other owners of their responsibilities. These revisions could be interpreted as an obligation of the TO to educate other utilities regarding their responsibilities. BC Hydro's understanding, in line with the verbal drafting team's clarifications during the July 6, 2022 industry webinar, is that to meet the intent of Requirement R1 (including Part 1.3) the TO is only required to provide notification to other owners of BES Elements subject to PRC-002 once this identification was made in accordance with Part 1.1. Also, the notification required in Part 1.3 is necessary only for newly identified BES Elements, or BES Elements that no longer require to have SER of FR data recorded. Please confirm whether this understanding is accurate. BC Hydro recommends that the Requirement R1 Part 1.3 be revised to remove the "of their responsibilities" wording. Below is suggested wording for Requirement R1 Part 1.3.	

"**1.3** Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners in accordance with Part 1.2."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Thomas Foltz - AEP – 5	
Answer	No
Document Name	
Comment	
AEP would like to express its overall support of the first phase of Project 2021-04. Our negative votes in this ballot period are in response *only* to our objections stated below that the illustrative examples are provided outside of the standard within in the Technical Rationale document, rather than embedded within the standard itself. Technical Rationale documents are to assist in the technical understanding of a requirement and/or Reliability Standard, and are not to include compliance examples or compliance language. That being said, the examples provided in the proposed Technical Rationale document on pages 4 through 9 appear to go beyond mere "technical understanding" of the obligations and could possibly be referred to in determination of compliance of those obligations. As such, we believe it would be more appropriate for this content to be embedded within the standard itself, perhaps as an "Attachment 3."	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Per NERC guidelines, the examples provided in the Technical Rationale cannot be added as an attachment. The Technical Rationale is already added as a reference to the standard.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Instead of making the Transmission Owner state in their notification that another owner is responsible for SER and/or FR data, PRC-002 should clearly state compliance responsibilities for all entities. BPA suggests R1 be restructured to clearly state what information the notifications shall contain. R1 should also state owner responsibilities in the event that a notification is received from another owner that SER and/or FR data is not being recorded by the Transmission Owner who identified the BES bus. This allows for compliance responsibility to be stated in the standard rather than have Transmission Owners mandate compliance responsibilities to other BES element owners. If the Transmission Owner does not have any BES Elements that do not have SER and/or FR data per PRC-002-4, BPA feels the notifications to other owners is still valuable to ensure PRC-002 compliance has been communicated to all other owners. BPA realizes this suggested change also impacts the changes to PRC-002-4 Technical Rationale. However, if notifications are needed regardless of whether or not another owner requires SER and/or FR data, the provided examples in the PRC-002-4 Technical Rationale for R1 may not be needed.

Suggested R1 changes are as follows:

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-002-4, Attachment 1.

1.2. Notify other owners of their BES Elements connected directly to those BES buses *identified in Part 1.1. This notification shall:*

1.2.1 *Be sent within 90 calendar days of completion of Part 1.1.*

1.2.2 *Include identified BES Elements where the Transmission Owner has SER and/or FR data that meet the requirements of PRC-002-4.*

***1.2.3** Include identified BES Elements where the Transmission Owner does not have SER and/or FR data and will require SER and/or FR data monitoring from the connected owner to meet the requirements of PRC-002-4.*

***1.2.4** Include identified BES Elements, if any, that were removed from the BES bus list identified in Part 1.1 and no longer require SER and/or FR data to meet the requirements of PRC-002-4.*

***1.3.** Review notifications received under Part 1.2 to ensure BES Elements identified under Part 1.2.3 meet the requirements of PRC-002-4.*

1.4. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners *in accordance with Part 1.2.*

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The intent of this SAR was to reduce the number of notifications and the compliance burden. Notifying entities when data is not needed was the main issue we were trying to resolve.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The MRO NSRF agrees with revising R1 to clarify the notification and responsibility for FR/SER data. These revisions will reduce the compliance evidence scope for storing notifications that do not require the recipient owner to take action.

The examples in the Technical Rationale document for Figures 1-8 are helpful. We request the team consider providing some example diagrams or clarification to further define “directly connected” for 1) how a center breaker is addressed on a breaker and a half configuration since these breakers do not appear to be “directly” connected to a bus, 2) how a line connected shunt reactor breaker is addressed that is inside the substation boundary but on the line side of two ring or breaker and a half breakers.

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Thanks for your comment. Per NERC guidelines, the examples provided in the Technical Rationale cannot be added as an attachment. The Technical Rationale is already added as a reference to the standard.	
Richard Jackson - U.S. Bureau of Reclamation – 1	
Answer	No
Document Name	
Comment	
Reclamation supports the attempt to clarify R1 but recommends additional clarity is needed regarding the scope of BES Elements in R1.2. According to Attachment 1, each TO is responsible to evaluate equipment it owns. R1.2 brings in other owners, so it seems obvious that one TO would not be responsible for recording SER or FR data on another owner's equipment, yet the TO is required to notify the other owner of this. Reclamation recommends R1.2 be reworded to clarify the notification goes to "owners of other BES Elements…". Reclamation recommends removing the proposed last sentence of R1.2 ("If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days.") A compliance obligation to perform this notification does not impact reliability and has no value.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No

Document Name	
Comment	
MidAmerican supports MRO NSRF comments: The MRO NSRF agrees with revising R1 to clarify the notification and responsibility for FR/SER data. These revisions will reduce the compliance evidence scope for storing notifications that do not require the recipient owner to take action. The examples in the Technical Rationale document for Figures 1-8 are helpful. We request the team consider providing some example diagrams or clarification to further define “directly connected” for 1) how a center breaker is addressed on a breaker and a half configuration since these breakers do not appear to be “directly” connected to a bus, 2) how a line connected shunt reactor breaker is addressed that is inside the substation boundary but on the line side of two ring or breaker and a half breakers.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team defined “directly connected” as a footnote in R1. In addition, the Technical Rationale includes a Reactor example and the application of directly connected.	
Deanna Carlson - Cowlitz County PUD – 5	
Answer	No
Document Name	
Comment	
The language as proposed in R1 Part 1.2 and 1.3 needs to be clarified to remove the interpretion that obligaties/mandates the TO to set responsibilities of other utilites.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3 – RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) appreciates the opportunity to respond and thanks the drafting team for their efforts. While the changes to R1 do not directly impact SIGE's procedures, SIGE recognizes the potential that the revisions may be burdensome on industrial customers and municipalities that may not readily have access to SER or FR data at the time of notification.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The Standard is only applicable to NERC registered Transmission and Generator Owners that own BES Element identified under PRC-002. Industrial customers and municipalities, unless they are registered TO or GO, have no PRC-002 compliance responsibility .	
Daniela Atanasovski - APS - Arizona Public Service Co. – 1	
Answer	No
Document Name	
Comment	

AZPS supports the revisions to Requirement 1 in principal but recommends that the STD incorporate the revised language, suggested in EEI's submittal of comments, to clarify the language within R1, subpart 1.3 to the following:

"Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, **if the BES buses for which sequence of events recording (SER) and fault recording (FR) data is required has changed,** then notify other owners of their responsibilities **as it relates to the affected** BES Elements, in accordance with Part 1.2."

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.

Russell Noble - Cowlitz County PUD – 3

Answer	No
Document Name	

Comment

The language as proposed in R1 Part 1.2 and 1.3 needs to be clarified to remove the interpretation that obligates/mandates the Transmission Owner to set responsibilities of other utilities.

Please see BPA's suggested edits.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC (CEHE) recommends the following revisions to part 1.2 for clarity.

1.2 Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that *the other owner* is responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the *other* owner of a BES Element is no longer required to have SER or FR data, notify the *other* owner within 90 calendar days.

CEHE recommends that Part 1.3 include a reference to the implementation language that has been moved from the implementation plan to R13.

1.3 Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners of their responsibilities in accordance with Part 1.2 *and implement the re-evaluated list of BES buses as per Requirement R13 Part 13.1.*

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The R1.2 is revised for added clarity.	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	

MPC supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team defined “directly connected” as a footnote in R1.	
David Jendras - Ameren - Ameren Services – 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The drafting team takes the position that notifications should be sent to all owners with BES Elements directly connected to the buses identified during the re-evaluation where SER or FR data is not already being recorded by the identifying T.O. Using the language proposed by EEI would only require notification to owners of BES Elements directly connected to newly identified buses or removed buses. Language was revised after comments to try to further clarify.	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 6, 5; Jennifer Flandermeyer, Evergy, 1, 3, 6, 5; Jeremy Harris, Evergy, 1, 3, 6, 5; Marcus Moor, Evergy, 1, 3, 6, 5; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the response of the Edison Electric Institute (EEI) to questions #1.	

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The drafting team takes the position that notifications should be sent to all owners with BES Elements directly connected to the buses identified during the re-evaluation where SER or FR data is not already being recorded by the identifying T.O. Using the language proposed by EEI would only require notification to owners of BES Elements directly connected to newly identified buses or removed buses. Language was revised after comments to try to further clarify.

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	
Comment	

Oncor appreciates the opportunity to respond and thanks the drafting team for their efforts. Oncor supports comments provided by CenterPoint Energy Houston Electric, LLC (CEHE) as follows:

1.2. Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that *the other owner* is responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the *other* owner of a BES Element is no longer required to have SER or FR data, notify the *other* owner within 90 calendar days.

CEHE recommends that Part 1.3 include a reference to the implementation language that has been moved from the implementation plan to R13.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners of their responsibilities in accordance with Part 1.2 *and implement the re-evaluated list of BES buses as per Requirement R13 Part 13.1.*

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See Comments Submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the clarification suggested in the EEI comment. On behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The language within R1, subpart 1.3 should be clarified and we offer the following: 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, **if the BES buses for which sequence of events recording (SER) and fault recording (FR) data is required has changed,** then notify other owners of their responsibilities **as it relates to the affected** BES Elements, in accordance with Part 1.2.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE abstains.	
Likes 0	

Dislikes 0	
Response	
Thanks for taking time to review and your support.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA) and Members	
Answer	No
Document Name	
Comment	

The SAR from Glencoe noticeably identifies two issues. The proposed standard revision addresses only one of those issues (and we believe, insufficiently). The original SAR (Before SDT added some items to the list) identifies the following two issues:

1) R1.2 infers all owners of BES Elements connected to the identified buses should provide SER and FR data, regardless of what type of Element they own, while R3 clearly identifies that FR data is only required for two categories of Elements – Transformers with low side operating voltage of 100kV or above and Transmission lines. This means that entities that own transformers with a low side operating voltage below 100kV are not required to provide FR data but are being sent notifications per R1.2 with the implication they must provide it. The proposed standard revisions do nothing to clear up this issue.

2) Since all owners, whether joint or sole, of every BES Element connected to the identified bus or buses, are being notified, many owners are being notified but are not in a position to capture data that is consistent with the intent of the standard. Specifically, it is quite common for ownership to change along the length of a transmission line, often many miles away from the bus that was identified in R1.1. As such, the "remote joint owner" of the BES Element has no equipment within the substation fence of the bus that was identified and is not in any position to capture any data relative to the identified bus, since it has no measurement equipment in that location. It was clearly not the original intent of the standard to require that every element connected to an identified bus have measurements at both ends (remote and local). We believe the intent of the original standard was clear that when a bus is identified, measurements obtained would be at the local bus location (whether terminal flows or bus voltages, they would be at that bus location). Modifying the language in R1.2 and R3 to include "directly connected" unfortunately does not fix the clear overreach that many auditors have inferred. If a transmission line is "jointly owned",

they consider it the responsibility of both owners to obtain the FR and SER data, even though in most cases the “joint” owner takes over ownership at the remote end of the line.

In order to fully address the original SAR (as we read it), the standard should be revised to make it clear only owners of equipment local (again, Directly Connected doesn’t help since the term BES Element has no fractional ownership in its definition) to the substation bus identified have the obligation to record data, and it should be clarified that only those entities that own BES Elements listed in R3.2 must provide FR data regardless of receipt of a notification. Ideally no notification would be required but SER data coverage must also be considered, since today both are performed with one notification.

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team defined “directly connected” as a footnote in R1 and does not include transmission lines or transformers with a secondary less than 100 kV.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Clarification is required with respect to required notifications. Suggestion is made to include in Appendix 1 the BES Elements exclusion of the Transformers that have a low-side operating voltage below 100kV. This will eliminate the unnecessary notification of BES Element Owners in accordance to R1, only to exclude it afterwards as per R3, Part 3.2, sub 3.2.1.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Drafting team defined “directly connected” as a footnote in R1. The definition includes the exclusion of Transformers that have a low-side operating voltage below 100kV.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 5 – WECC	
Answer	No
Document Name	
Comment	
PacifiCorp agrees with revising R1 to clarify the notification and responsibility for FR/SER data. These revisions will reduce the compliance evidence scope for storing notifications that do not require the recipient owner to take action. The examples in the Technical Rationale document for Figures 1-8 are helpful. We request the team consider providing some example diagrams or clarification to further define “directly connected” for 1) how a center breaker is addressed on a breaker and a half configuration since these breakers do not appear to be “directly” connected to a bus, 2) how a line connected shunt reactor breaker is addressed that is inside the substation boundary but on the line side of two ring or breaker and a half breakers.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team defined “directly connected” as a footnote in R1. In addition, the Technical Rationale includes a Reactor example and the application of directly connected.	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	No
Document Name	
Comment	

CPS Energy feels that 1.2 still needs work to make clear who is responsible for providing SER or FR data in stations where multi-owners are involved. When used in conjunction with the technical reference document (Technical Rationale), it is mostly fine, however, without the technical reference, the standard is not entirely clear who is responsible for busses with multi-owners. In the first sentence of 1.2, the sentence “for which the Transmission Owner does not record SER or FR data” really needs to be reworded to include “and is not responsible for recording SER or FR data” to notify the other owner(s) of the responsibility for recording the SER or FR data. However, need to remove a new requirement obligation of the studying entity, in R1 Part 1.2 and 1.3, to be required to assign requirement obligations to another entity; this needs to be fixed to remove the interpretation that obligates the Transmission Owner to set responsibilities of other entities.

Examples in standard would be preferred; the best solution is to provide complete clarity and add the technical reference with diagrams and explanations to the end of the standard, as is done in PRC-025-2, for example.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden. Drafting team will define “directly connected” as a footnote in R1. In addition, the Technical Rationale will include a Reactor example and the application of directly connected.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	Yes
Document Name	

Comment

WECC agrees with the idea and intent but believes the wording in 1.2 could be improved.
1) it states "Notify other owners of BES elements, for which the Transmission Owner does not record SER of FR data..." This could be confusing since the other "owner" could also be a Transmission Owner.

2) while recording of SER and FR data is one way of providing the data. Calculation of required data is also possible. So use of "recording" may be implying the need for equipment that is not explicitly specified by the standard. WECC recommends that the Drafting Team consider the following change in wording: "Notify other owners of BES elements, for which the Transmission Owner performing the assessment per Attachment 1 does not obtain SER or FR data, that the BES Element owners are responsible for providing the SER or FR data...."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no proposed comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review and support.	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no proposed comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for taking time to review and support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with these revisions. The R1 changes provide clarity that should reduce the number of unnecessary notifications made and received by each entity.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
NRG generally agrees with the revisions. The additions make the requirements clear regarding who has the obligations for installing SER or FR recorders. We are hesitant that the Transmission Owner is the party making the decision regarding whether it will be them or the Generator Owner to install the recorder. We would favor a third party, like an RC, to make the determination or to encourage discussions between the affected owners. NRG has had good experiences working with TOs to install recorders in the past and encourage discussions between the TO and GO regarding who should perform the installation.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FE suggest clarifying R1.3 to state "notify other owners of changes in their responsibilities". 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and **if necessary, notify** other owners **of changes in their responsibilities**, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan. The reason for this modification is that the "other owners" have been previously notified in Part 1.2 of their responsibility; so, the "other owners" should only be notified of changes to their responsibilities.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes

Document Name	
Comment	

PG&E supports the revisions to Requirement R1, but has the following input the SDT should consider for R1.2:

R1.2 indicates for the Transmission Owner - "… If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days."

PG&E concern is the language does not address what happens if there are changes between the 5-year evaluation periods resulting in changes to the SER and FR data collection capabilities. There does not appear to be any requirement to communicate those changes so the owner either stops the work that is no longer required or starts work that would be required to maintain the reliability of the Bulk Electric System (BES).

PG&E recommends the SDT consider the above and determine how to address this condition to avoid work that is no longer required or could lead to reliability issues for work that should be done

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Standard requires re-evaluation at least once every 5 calendar years. The drafting team cannot require notification any more frequently without requiring more frequent evaluation. However, T.O.s can evaluate as often as they would like and provide courtesy notifications at their own discretion.

Sheila Suurmeier - Black Hills Corporation – 5

Answer	Yes

Document Name	
Comment	
Black Hills Corpoariton agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Claudine Bates - Black Hills Corporation – 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Micah Runner - Black Hills Corporation – 1	
Answer	Yes
Document Name	

Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Josh Combs - Black Hills Corporation – 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Tri-State agrees with the revisions to Requirement 1 however, proposes the following language for clarity: "Notify other owners of BES Elements directly connected to those BES buses, for which the Transmission Owner does not record SER or FR data that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days."	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Drafting team recognizes need for rewording R1. It has been reworded to clarify notifications and compliance responsibilities in order to reduce the number of notifications and compliance burden.	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	Yes
Document Name	
Comment	
The suggested revisions to Requirement 1 are consistent with the principle that the TO/TP remain responsible for identification of locations requiring FR/SER/DDR capability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Wendy DeVries - CMS Energy - Consumers Energy Company - 1,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Brendan Baszkiewicz - Eversource Energy - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ayslynn McAvoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
David Reinecke - Seminole Electric Cooperative, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	

Comment	
Texas RE noticed the term "owners" throughout the requirements. Texas RE recommends clarifying that "owners" refers to NERC-registered Transmission Owners or Generation Owners to eliminate the possibility that a non-NERC registered entity may be designated within a Facility that requires FR/SER data per a registered entity's determination to ensure effective review of materials after an event.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. This is unnecessary, because it is covered by the Applicability section of the standard. Only entities listed in the Applicability section can be held to the requirements of the standard.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Dana Showalter - Electric Reliability Council of Texas, Inc. – 2	
Answer	
Document Name	
Comment	

No response.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	
Document Name	
Comment	
SRC submits no response to this question.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

2. Do you agree with including the implementation plan information in proposed Requirement R13?	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	No
Document Name	
Comment	
Not necessarily against the 3-year term; would prefer calendar years or calendar months (e.g. 36 calendar months). Also, make clear that both Transmission Owner and other owners of BES elements notified per R1/R5 need to have the equipment installed in 3 years; same concern, 3-years from what; fix by specifying three calendar-years from date notified. Noted the Technical Rationale references "Three (3) calendar years.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The time permitted in R13 is changed from three-years to three calendar years. R13 is revised to clarify that the implementation trigger starts upon completing re-evaluation or receiving notification under Requirement R1, Part 1.3.	
Mike Magruder - Avista - Avista Corporation – 1	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The re-evaluation which may trigger notification is expected to occur every five years.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 5 – WECC	
Answer	No
Document Name	
Comment	
PacifiCorp agrees with the need for including the re-evaluation and implementation plan as R13. It aligns with the prior implementation plan and will clearly carry forward newly applicable BES elements within the standard. We would like to request clarification for the meaning of the word “notification” in 13.1. For example, a TO performs the 5-year re-evaluation and they do not need to notify others and are not notified by others. In this case when would the 3-year timeline start? The NSRF recommends the following revised language: “Within three (3) calendar years of notification under Requirement R1, Part 1.2, or completion of Requirement R1, Part 1.3, as applicable, have SER or FR data …”	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The time permitted in R13 is changed from three-years to three calendar years. R13 is revised to clarify that the implementation trigger starts upon completing re-evaluation or receiving notification under Requirement R1, Part 1.3.	
Constantin Chitescu - Ontario Power Generation Inc. – 5	

Answer	No
Document Name	
Comment	
Due to current Supply Chain challenges and based of Planned Outages Schedule interval of 3 years for nuclear generating units a suggestion is made that where the determination has been made that the DMEs are required to be installed, the implementation of the SER, FR, and DDR shall be the result of commonly agreed scheduled, negotiated between the TO and GO.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three-years to three calendar years.	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	No
Document Name	
Comment	
This approach seems inconsistent with the "effective date" approach identified in other NERC requirements with staged implementation dates and appears to dilute the effectiveness of the Implementation Plan concept.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Please note that R13 only applies when new BES buses where SER/FR is required are identified during a re-evaluation. The implementation plan of the PRC-002-2 version did not provide staged implementation plan for this. In this revision, the requirement is simply moved from the implementation plan to the main standard.

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE is concerned with the prescriptive nature of a three (3) year notification clock. Perhaps a reasonable Corrective Action Plan could be developed?

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The re-evaluation which may trigger notification is expected to occur every five years. If new BES buses/BES Elements where SER/FR/DDR data is required is identified during a re-evaluation, then those are required within three calendar years of identification/notification.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

We agree with including the implementation plan information within proposed Requirement R13 but also suggest Part 13.1 and Part 13.2 be revised to state, “Within three (3) calendar-years…”, instead of “Within three (3) years. Three calendar-years would be helpful for the installation of new equipment, since a calendar-year ends on December 31st vs. stating within (3) years which could be interpreted as three years from the notification date. The Technical Rationale references, “Three (3) calendar years…”

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. the time permitted in R13 is changed from three years to three calendar years.	
Daniel Gacek - Exelon – 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the clarification suggested in the EEI comment. On behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI’s comment.	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See Comments Submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. Please see response to EEI's comment.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
In consideration of recent material shortages and supply chain disruptions, Oncor recommends an implementation period of 5 calendar years for Requirement 13 Part 13.1 and Part 13.2.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three-years to three calendar years.	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 6, 5; Jennifer Flandermeyer, Evergy, 1, 3, 6, 5; Jeremy Harris, Evergy, 1, 3, 6, 5; Marcus Moor, Evergy, 1, 3, 6, 5; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the response of the Edison Electric Institute (EEI) to questions #2.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. Please see response to EEI's comment.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. – 3	
Answer	No
Document Name	
Comment	
Northern Indiana Public Service Company supports the addition of Requirement R13, but recommends changing the period of time from "three year" to "three calendar year" to be consistant with other parts of the standard.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The time permitted in R13 is changed from three years to three calendar years.	
David Jendras - Ameren - Ameren Services – 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI's comment.	

Karl Blaszkowski - CMS Energy - Consumers Energy Company – 3	
Answer	No
Document Name	
Comment	
I'm concerned that 3 years may be insufficient to plan/design new SER/FR installations, procure equipment, and install the equipment, particularly for power plants (GO) where such installation should be coordinated with plant outage schedules in order to not adversely affect plant availability. The 3 year implementation time frame might be to constrictive especially in light of recent material shortages. Suggest a 7 year time frame would allow BES element owners time to work the project into their schedule and procure equipment and resources.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three-years to three calendar years.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports MRO NERC Standards Review Forum comments.	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to comment by MRO NERC Standards Review Forum.	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC recommends an implementation period of 5 calendar years for Requirement 13 Part 13.1 and Part 13.2.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three-years to three calendar years.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 – RF	
Answer	No
Document Name	
Comment	

We are concerned that 3 years may be insufficient to plan/design new SER/FR installations, procure equipment, and install the equipment, particularly for power plants (GO) where such installation should be coordinated with plant outage schedules in order to not adversely affect plant availability.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three-years to three calendar years.	
Kenisha Webber - Entergy - NA - Not Applicable – SERC	
Answer	No
Document Name	
Comment	
Recommend a similar path that PRC-026 R3 and R4 takes: upon notification of the need to install a DDR (from R5) create a corrective action plan and implement it.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time or changing to develop a CAP upon identification/notification is not in the scope of this SAR. However, the time permitted in R13 is changed from three-years to three calendar years.	
Daniela Atanasovski - APS - Arizona Public Service Co. – 1	

Answer	No
Document Name	
Comment	
AZPS supports the inclusion of the implementation plan in proposed Requirement R13 but recommends that the STD incorporate the revised language, suggested in EEI's submittal of comments, to clarify the language within R12, subparts 13.1 and 13.2 to the following: "Within three (3) calendar-years…", instead of "Within three (3) years. Three calendar-years would be helpful for the installation of new equipment, since a calendar-year ends on December 31st vs. stating within (3) years which could be interpreted as three years from the notification date. The Technical Rationale references, "Three (3) calendar years…"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The time permitted in R13 is changed from three years to three calendar years.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3 – RF	
Answer	No
Document Name	
Comment	
SIGE recommends the implementation period be amended from "three (3) years" to "five (5) calendar years". The addition of "calendar" is to mirror the language in R1. SIGE believes the three-year implementation period may be too restrictive given set project cycles and several challenges faced by the industry including outage constraints due to capacity shortfalls and long lead-times due to supply chain issues.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time or changing to develop a CAP upon identification/notification is not in the scope of this SAR. However, the time permitted in R13 is changed from three years to three calendar years.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. – 3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF comments: The MRO NSRF agrees with the need for including the re-evaluation and implementation plan as R13. It aligns with the prior implementation plan and will clearly carry forward newly applicable BES elements within the standard. We would like to request clarification for the meaning of the word "notification" in 13.1. For example, a TO performs the 5-year re-evaluation and they do not need to notify others and are not notified by others. In this case when would the 3-year timeline start? The NSRF recommends the following revised language: "Within three (3) calendar years of notification under Requirement R1, Part 1.2, or completion of Requirement R1, Part 1.3, as applicable, have SER or FR data …"	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The requirement R13 is revised to clarify that timeline starts upon completing re-evaluation or receiving notification. The time permitted in R13 is also changed from three-years to three calendar years.	
Richard Jackson - U.S. Bureau of Reclamation – 1	

Answer	No
Document Name	
Comment	
The "General Considerations" bullet in the implementation plan pertaining to Requirement R13 is unclear. Reclamation recommends aligning R13 with the five-year requirement to avoid the potential for entities to be placed in a constant state of review.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The "general considerations" bullet in the implementation plan is revised to add clarity. The three year time permitted in R13 was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time or changing to develop a CAP upon identification/notification is not in the scope of this SAR. However, the time permitted in R13 is changed from three-years to three calendar years.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The MRO NSRF agrees with the need for including the re-evaluation and implementation plan as R13. It aligns with the prior implementation plan and will clearly carry forward newly applicable BES elements within the standard. We would like to request clarification for the meaning of the word "notification" in 13.1. For example, a TO performs the 5-year re-evaluation and they do not need to notify others and are not notified by others. In this case when would the 3-year timeline start? The NSRF recommends the following revised language: "Within three (3) calendar years of notification under Requirement R1, Part 1.2, or completion of Requirement R1, Part 1.3, as applicable, have SER or FR data …"	

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Thanks for your comment. The requirement R13 is revised to clarify that timeline starts upon completing re-evaluation or receiving notification. The time permitted in R13 is also changed from three years to three calendar years.	
Thomas Foltz - AEP – 5	
Answer	No
Document Name	
Comment	
While AEP acknowledges that the existing Implementation Plan for the standard under enforcement has a “three year” period of time to have data in response to notification(s) under R1, we recommend changing this to “three calendar years” under the proposed R13.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The time permitted in R13 is changed from three years to three calendar year.	
Scott Kinney - Avista - Avista Corporation – 3	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The re-evaluation which may trigger notification is expected to occur every five years.	
Glen Farmer - Avista - Avista Corporation – 5	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The re-evaluation which may trigger notification is expected to occur every five years.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Suggest implementation period be amended from 3-years to 4-years. The requirement for a 3-yr compliance period will conflict with previously scheduled and planned outage/maintenance/fueling cycles since: (a) the ability to install equipment is significantly affected by outage constraints, equipment lead-times and availability and, (b) the Covid pandemic has significantly impacted supply chain and availability of work resources. Overall, the 3-year window creates a condition whereby an entity must fast-track the installation of monitoring equipment over other work which better supports grid stability. Additionally, the 3-year implementation period is especially disadvantageous to nuclear sites with 2-year refueling cycles/outages.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three years to three calendar years.	
Wendy DeVries - CMS Energy - Consumers Energy Company - 1,5 – RF	
Answer	No
Document Name	
Comment	
The 3 year implementation time frame might be to constrictive especially in light of recent material shortages. Suggest a 7 year time frame would allow BES element owners time to work the project into their schedule and procure equipment and resources.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three years to three calendar years.	
Donna Wood - Tri-State G and T Association, Inc. – 1	
Answer	Yes
Document Name	
Comment	

Tri-State agrees with moving the three year notification requirement from the implementation plan directly to the standard to provide more clarity.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Josh Combs - Black Hills Corporation – 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI's comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF has no comments.	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Micah Runner - Black Hills Corporation – 1	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI's comment.	
Claudine Bates - Black Hills Corporation – 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Please see response to EEI’s comments.	
Sheila Suurmeier - Black Hills Corporation – 5	
Answer	Yes
Document Name	
Comment	
Black Hills Corpoariton agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI’s comment.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E supports the proposed Requirement R13, but has the following question and recommendation: Does the three-year implementation trigger start on the day that the affected BES Element owner is informed of their new SER, FR, and/or DDR data obligation(s). The current Requirement language is not clear on the trigger start.	

PG&E recommends this be clearly indicated to avoid interpretation differences between the Registered Entity and Regional Entity	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The R13 is revised to clarify that the implementation trigger starts upon completing re-evaluation or receiving notification under Requirement R1, Part 1.3. The time permitted is also extended from three years to three calendar years.	
Russell Noble - Cowlitz County PUD – 3	
Answer	Yes
Document Name	
Comment	
Yes, but consider stating three calendar years as noted by APS.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The time permitted is changed from three years to three calendar years.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with including the implementation plan information in the proposed Requirement R13, however believes additional clarity should be provided. Proposed language indicates a 3-year implementation plan upon receipt of notification in R1.3, however a 3-year	

implementation should also be included for the entity performing the reevaluation and identifies their own buses in R1.1. This seems implied but should be explicit.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The requirement is revised to include entities that perform re-evaluation.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
No comment at this time.	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed Requirement R13, however, recommends the replacement of "within three (3) years of notification" to three (3) calendar years of notification. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The time permitted in R13 is changed from three years to three calendar years.	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed Requirement R13, however, recommends the replacement of "within three (3) years of notification" to three (3) calendar years of notification.	

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The time permitted in R13 is changed from three years to three calendar years.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Since the term Calendar Year is used in Parts 1.3 and 5.4, WECC recommends that the Drafting Team consider replacing the words "Three (3) years" with the words "36 months." This would provide more clarity than using two different meanings of the term "year" within the same standard and would be consistent with other terminology in the standard.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The time permitted in R13 is changed from three years to three calendar years.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro proposes that language in sections 13.1. and 13.2. be revised to read:	

13.1. Within three (3) years of **receiving** notification under Requirement R1, Part**s 1.2 and** 1.3, have SER or FR data as applicable for BES Elements directly connected to BES buses identified during the re-evaluation. **13.2.** Within three (3) years of **receiving** notification under Requirement R5, Part**s 5.3 and** 5.4, have DDR data for BES Elements identified during the re-evaluation.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The requirement is clarified by adding "receiving" before notification. R1, Part 1.3 already refers to Part 1.2 so it is not necessary to reference Part 1.2.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA) and Members	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
David Reinecke - Seminole Electric Cooperative, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Ayslynn McAvoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Brendan Baszkiewicz - Eversource Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	
Document Name	
Comment	

SRC submits no response to this question.

Likes 0	
Dislikes 0	

Response
Thanks for your support.
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT noticed that the Implementation Plan for PRC-002-4 states, "The elements of the Implementation Plan for PRC-002-3 are incorporated herein by reference and shall remain applicable to PRC-002-4." And the Implementation Plan for PRC-002-3 contains the following language:

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.

Thus, the three-year compliance window for BES Elements added pursuant to a re-evaluation in R1 or R5 exists pursuant to the Implementation Plan, although the SAR expressed desire to remove this compliance window from the Implementation Plan. In this case, R13 should be removed.

If the compliance window is removed from the Implementation Plan, ERCOT notes that the proposed R13 language does not fully address the compliance-window issue. R13 provides a compliance window, but does not tie the window specifically to the applicable data requirements, such as R2. Each data requirement may need to reference R13 or the SDT may want to consider putting the three-year compliance window language within each requirement rather than as a stand-alone requirement.

Regardless of where the implementation window lies, the language should be clear that the three-year compliance window only applies to *new BES Elements*, not all BES Elements, identified pursuant to the R1 and R5 review cycle.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SAR did not express desire to remove compliance window, instead proposed to move this compliance window from the PRC-002-2 implementation plan to the main standard itself. This is why Requirement R13 is included in this revision. During re-evaluation, BES buses/BES Elements where SER/FR/DDR data is required in R1/R5. Requirements such as R2, R3, R6 refers to R1/R5 as applicable. R13 is only specifying the implementation time for new BES buses/BES Elements identified during the re-evaluation.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	
Document Name	
Comment	
Texas RE appreciates the SDT addressing Texas RE's concern and moving the periodic requirements associated with R1 and R5 away from the Implementation Plan and into Requirement R13. Texas RE recommends stating specifically which elements from the PRC-002-3 Implementation Plan are incorporated into the PRC-002-4 Implementation Plan. The PRC-002-4 Implementation Plan contains the phrase: "the elements of the Implementation Plan for PRC-002-3 are incorporated herein by reference and shall remain applicable to PRC-002-4". It is not clear which elements are incorporated by reference. The PRC-002-3 Implementation Plan, it states, "unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4, PRC002-2, PRC-023-4, and PRC-026-1 are incorporated herein by reference and shall remain applicable to FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2." It is unclear which is carried through to the proposed PRC-002-4 Implementation Plan as there is no section in either Implementation Plan labeled as "elements".	

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The implementation plan is revised for clarity.	

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.	
Wendy DeVries - CMS Energy - Consumers Energy Company - 1,5 - RF	
Answer	
Document Name	
Comment	
The implementation time frame of 3 years isn't long enough for a BES element owner to gather bids, procure materials, and schedule the work, and then install the equipment. Time frame should be extended to 7 years if not that at least, 5 years.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three years to three calendar years	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
Manitoba Hydro proposes that language for requirement R3 be updated to read “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 **that are directly** connected to the BES buses identified in Requirement R1".	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. The “connected directly” is replaced with “directly connected” in R3.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
While R13 will have specified implementation times, the Violation Severity Levels for R13 do not address any severity with respect to the time specified for implementation in R13 as they do for R1 and R5. Is this intentional?	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The VSLs for R13 are revised and now addresses severity with respect to specified time in the requirement.	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Thomas Foltz - AEP – 5	
Answer	
Document Name	
Comment	
AEP thanks the Standards Drafting Team for their efforts, and for pursuing AEP's previous recommendation for the two proposed SARs to each be dealt with in separate project phases.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	
Document Name	
Comment	

R13 should apply to all of R1 and R5 and not just R1.3 or R5.4. SER and/or FR data should be required within 3 years whether an applicable BES Element is identified during the Transmission/Generator Owner's re-evaluation or if a BES Element is identified per receipt of a notification from another owner per R1.2 (specifically R1.2.3 if BPA's suggested changes to R1 are accepted).

The 15% margin proposed in Attachment 1, Step 7 seems very arbitrary and doesn't seem to provide any added reliability value other than making the logistics of having to add SER or FR equipment less burdensome. Unless there is proof that a 15% margin does not adversely impact reliability of the grid, the margin should not be added.

Overall:

- The Standard should not rely on other TO/GO's to mandate requirements on other TO/GO's.
- The Standard should define what information is required in the notifications.
- All Requirements within the Standard should have a foundation in improving or maintaining reliability of the transmission system.

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

R13 is revised to clarify that the implementation trigger starts upon completing re-evaluation or receiving notification under Requirement R1, Part 1.3. The re-evaluation requirement is specified in R1, Part 1.3 and R5, Part 5.4. The purpose of R13 is to specify time period allowed to have SER/FR/DDR data, as applicable, for BES buses/BES Elements identified during the re-evaluation. R13, Part 13.1 is revised to clarify that time specified is applicable to TOs completing re-evaluation or receiving notification.

The 15% margin proposed in Attachment 1, step 7 is applicable to small entities which are only required to have SER/FR data at one BES bus. Given that the transmission system involved is small, it is does not appear that this flexibility would result in any adverse reliability impact on the grid. The language is revised for added clarity and example is included in technical rationale. The Requirement R1, Part 1.2 is revised. The proposed language does not rely on other TO/GO's to mandate requirements on other TO/GOs. The SDT added an example of a notification in the technical rationale. The SDT believes that it is not necessary to define notification information in the standard itself. The SDT agrees that requirements should have a foundation in improving and maintaining reliability of the transmission system. Proposed revisions in this version are clarifying in nature.	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Thanks for your support.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	
The proposed change to Attachment 1 Step 7 allows the possibility of significant change over time without a required change in data recording location. Reclamation recommends each re-evaluated three phase short circuit MVA be compared to the originally evaluated three	

phase short circuit MVA and no change is required only if the re-evaluated measurement is within 15% of the original measurement. Comparing each re-evaluated measurement to its previous measurement would allow no change in location in perpetuity so long as the difference changed by no more than 15% each re-evaluation, even if the net change over time was ultimately more than 15%.

In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1 and Requirements R1 and R5 should be revised to include Planning Coordinators.

Reclamation recommends removing the proposed last sentence of R5.3 (“If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days.”) A compliance obligation to perform this notification does not impact reliability and has no value.

To clarify that in the case of multiple RCs, each RC is responsible for its own RC Area (reference NERC Glossary of Terms “Reliability Coordinator Area”), Reclamation recommends changing the language in R5.4 as follows:

From:

Re-evaluate all BES Elements under its purview at least once every five calendar years…

To:

Re-evaluate all BES Elements in its Reliability Coordinator Area at least once every five calendar years…

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The originally calculated SC MVA is not a good reference to compare. The system is expected to change over time, which is exactly why the re-evaluation is required. If system has changed then comparing to originally calculated SC MVA is not a good reference. For clarity, the language is revised, and an example is included in technical rationale.

In all interconnections, per applicability in 4.1.1., the standard applies to Reliability Coordinator. Not sure why planning coordinator is also sending notifications unless it is done on behalf of the reliability coordinator. Based on applicability in the standard, the reliability coordinator is ultimately responsible. The statement “if the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days” is removed from R5.3. The SDT discussed proposal to replace “under its purview” with “in its RC Area”. The words “under its purview” means the same and hence no change is made.

Alison Mackellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	

Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	
Document Name	

Comment	
No comment at this time	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
None	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	
Agree with BPA comments.	
Likes 0	
Dislikes 0	
Response	

Thanks for your support. Please see response to BPA's comment.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	
Consider the current uncertainty of supply chain issues and availability of parts.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Addressing uncertainty around supply chain and availability of parts is not in the scope of this SAR.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	
Document Name	
Comment	
The implementation time frame of 3 years isn't long enough for a BES element owner to gather bids, procure materials, and schedule the work, and then install the equipment. Time frame should be extended to 7 years if not that, at least 5 years.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three years to three calendar years.	

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	
Document Name	
Comment	
The implementation time frame of 3 years isn't long enough for a BES element owner to gather bids, procure materials, and schedule the work, and then install the equipment. Time frame should be extended to 7 years if not that, at least 5 years.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The three year time permitted was already included in the implementation plan of the PRC-002-2 version of this standard. In this revision, this requirement is simply moved to the main standard. Extending this permitted time is not in the scope of this SAR. However, the time permitted in R13 is changed from three years to three calendar years.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	

Answer	
Document Name	
Comment	

For R1.3, if the other owner is recording as notified per R1.2 and the 5-year re-evaluation per R1 indicates they are to continue to record, is a re-notification needed? Would this change the evidence retention for R1?

If FE's propose change in question 1 is accepted, should the Evidence Retention be revised in section B. Compliance, Part 1.2 to extend past 5 years if necessary to capture the last notification? Revision we suggest:

From:

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

To:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years or since the last notification in Part 1.2 or 1.3

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The R1, Part 1.2 requires notification upon re-evaluation in Part 1.3. Based on this evidence retention time specified for R1 is appropriate.

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	
Comment	

Ameren agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI's comments.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
In R5, Part 5.3, a new requirement was added for the RC to notify appropriate entities if a BES Element is no longer required to provide DDR data. This goes beyond the scope of the SAR; although the RC may notify parties when certain data is not needed, there is no reliability need or benefit for making this notification a requirement. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. Since R 5.4 requires this to be evaluated every five years, there is no need to further obligate the RC to notify when DDR data is not needed. Therefore, the language, "If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days" should be stricken.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The subject language is removed from R5, Part 5.3.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	

Document Name	
Comment	
PG&E has input on R5.3 which is the same as our comment and recommendation in Question 1 regarding R1.2. Please see our input for Question 1; the only difference is that R5.3 is related to the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Standard requires re-evaluation at least once every 5 calendar years. The drafting team cannot require notification any more frequently without requiring more frequent evaluation. However, T.O.s can evaluate as often as they would like and provide courtesy notifications at their own discretion.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	
Document Name	
Comment	
Delete the word "for" from the title of the IEEE C37.111 standard title. The correct name is (IEEE Standard Common Format for Transient Data Exchange (COMTRADE). VSL Table R11, change 11.1 to 11.2 in the sentence "The TO or GO as directed by R11, Part 11.1 provided the requested data more than x days" for all severity levels, as the Requirement for the requested data is R11.2 and not R11.1.	

Technical Rationale: The standard addresses SER, FR, and DDR data, therefore, consider removing the last sentence of the Technical Rationale, Page 4, the first paragraph after the bullets, that reads “As a result, this standard only requires DDR data”. Or clarifying the sentence for the requirements that require DDR data only. Technical Rationale: Page 11, Rationale R4, 3rd paragraph: should “protection System” be “Protection System”? Technical Rationale: Page 18, Rationale for R11, 2nd paragraph should read “Providing the data within 30 calendar days (or the granted extension time), subject to Part 11.1, allows for a reasonable time to collect the data and perform any necessary computations or formatting” should read “…subject to Part 11.2”, as the Requirement for the requested data is R11.2 and not R11.1. Technical Rationale: Page 19, 3rd paragraph “Requirement R11, Part 11.1 specifies the maximum time frame of 30 calendar days to provide the data.” Should read “Requirement R11, Part 11.2 specifies …” Technical Rationale: Page 19, 4th paragraph “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” should read “Requirement R11, Part 1.1 ….” For added clarity: suggest adding straight and ring bus examples in the technical rationale (similar to examples in figures 3 and 4 on pg. 6) where CB 3 is owned by TO B while TO A as a BES bus owner records SER and FR data for CB 3. And explain whether notification is required or not.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The standard and technical rationale is revised as applicable/suggested. Following statement is added in technical rationale for figures 3 and 4 to address last comment: For examples in Figures 3 and 4, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	
Document Name	
Comment	
In regards to R1.3 if a entity identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required through the assessment required in R1.1 what is the time-frame to get evidence and possibly install equipment?	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The Requirement R13, Part 13.1 is revised to clarify that time permitted also applies to TO completing re-evaluation per R1, Part 1.3.	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 6, 5; Jennifer Flandermeyer, Evergy, 1, 3, 6, 5; Jeremy Harris, Evergy, 1, 3, 6, 5; Marcus Moor, Evergy, 1, 3, 6, 5; - Alan Kloster	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the response of the Edison Electric Institute (EEI) to questions #3.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI’s comment.	
David Reinecke - Seminole Electric Cooperative, Inc. - 6	
Answer	
Document Name	
Comment	
In regards to R1.3 if an entity identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required through the assessment required in R1.1 what is the time-frame to get evidence and possibly install equipment?	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The Requirement R13, Part 13.1 is revised to clarify that time permitted also applies to TO completing re-evaluation per R1, Part 1.3.	
Sheila Suurmeier - Black Hills Corporation – 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Claudine Bates - Black Hills Corporation – 6	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Micah Runner - Black Hills Corporation – 1	

Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	
Document Name	
Comment	
See Comments Submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI’s comment.	
Marc Sedor - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	
Document Name	
Comment	

In regards to R1.3 if an entity identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required through the assessment required in R1.1 what is the time-frame to get evidence and possibly install equipment?	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The Requirement R13, Part 13.1 is revised to clarify that time permitted also applies to TO completing re-evaluation per R1, Part 1.3.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	
Document Name	
Comment	
Texas RE is concerned that the Technical Rationale for Requirement R1 references BES short circuit data from 2013. The grid has had a significant change in the resource mix since 2013, with the ERCOT region adding 11,650 MW of solar since 2013. Texas RE understands inverter-based resources will be addressed in the next phase of this project, with the SAR submitted by the IBRTF. Especially considering past and recent events in Odessa and California, as detailed in the Odessa Disturbance Report issued May 2021 and Multiple Solar PV Disturbances in CAISO dated April 2022, Texas RE encourages the SDT to consider a requirement for generators to have fault recording devices. Texas RE noticed in section B. Compliance 1.3 Compliance Monitoring and Enforcement Program the term “Spot Checking” should be “Spot Check”, “Compliance Violation Investigation” should be “Compliance Investigation”, “Self Reporting” should be “Self Reports” Texas RE recommends the SDT consider adding Self-Logging. **Attachment 1 Comments**	

Texas RE recommends clarifying which "list" is being referenced for each step. Texas RE has the following additional comments regarding clarifying the steps in Attachment 1.

Texas RE understands the methodology as follows: A list is created in Step 1. In Step 2 the list in Step 1 is reduced to 1500 MVA or greater (with zero buses meaning the process is complete). Step 3 reduces the list in Step 2 to the 11 buses with the maximum available calculated three-phase short circuit MVA.

Texas RE noticed Step 3 does not provide guidance for more than 11 BES buses (from list in Step 2) that have ***equal*** maximum available calculated three phase short circuit MVA. The attachment is assuming non-equal buses which many larger utilities may have within their footprint.

Texas RE recommends clarifying Step 5 to state the number should be 20% of the median or 120% of the median MVA level. As the language is currently drafted, it reads if the median level were 1500 MVA Step 5 result would be 300 MVA which would mean every bus in Step 2 would require FR and SER data. If in Step 2 you reduce the list to 1500 MVA or greater then Step 6 automatically includes every bus.

Step 2 explains to reduce the list of BES buses to 1500 MVA or greater. Step 4 explains to use the 20% median level determined in Step 5. If the 20% is 300 MVA, as per Texas RE's example above, is it the SDT's intent to look in this range?

Step 7 (where there are 1 or more but less than or equal to 11 BES buses) appears to possibly limit FR and SER data at "the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 2. In other words, if all buses (1 to a maximum of 11) have the same "highest maximum available calculated three phase short circuit MVA" is the Transmission Owner only required to select one (1) BES Bus? Even if they do not have the same "highest maximum available calculated three phase short circuit MVA", is the intent to only have FR and SER data at one (1) BES bus?

Likes 0	
Dislikes 0	
Response	
Thanks for your comments. The IRPTF SAR will be addressed in second phase of this project. The SDT reviewed/discussed comments related to attachment 1 but believes language as written is clear. Additionally, changes to attachment 1 are not in the scope of this SAR anyway.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF provides the following comments for consideration: *1. Draft #1 PRC-002-4:* *a. Recommend deleting page 2 as there are no new terms defined.* *b. R13.1 and R13.2 – Replace "Within three (3) years of notification…" with "Within three (3) calendar years of notification…".* *2. Attachment 1, Step 7:* *a. The proposed change to Attachment 1 Step 7 allows the possibility of significant change over time without a required change in data recording location. Recommend that each re-evaluated three phase short circuit MVA be compared to the originally evaluated three phase short circuit MVA and no change is required only if the re-evaluated measurement is within 15% of the original measurement.*	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. Page 2 is retained for now but will be removed at the end of process if not necessary. R13, Parts 13.1 and 13.2 are revised as suggested. The originally calculated SC MVA is not a good reference to compare. The system is expected to change over time, which is exactly why the re-evaluation is required. If system has changed then comparing to originally calculated SC MVA is not a good reference. For clarity, the language is revised, and an example is included in technical rationale.	
Daniel Gacek - Exelon – 1	
Answer	
Document Name	
Comment	
Exelon concurs with the clarification suggested in the EEI comment. On behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to EEI's comment.	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

ERCOT agrees with the SRC.

In R5, Part 5.3, the SDT placed a new requirement on the RC to notify owners if a BES Element is no longer required to have DDR data. This goes beyond the scope of the SAR; there is no reliability need or benefit to this notification. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. The language, "If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days" should be stricken.

Although not preferred, if the SDT retains the language regarding notification when DDR data is not required, ERCOT requests that the SDT add "of completing Part 5.1" at the end of the sentence: "If the owner of a BES Element is no longer required to have DDR data, notify the owner within ninety calendar days *of completing Part 5.1*."

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The subject statement is removed, as there is no reliability need or benefit.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Please consider aligning the format of PRC-002-4 into the most recent version of NERC Drafting Team Reference Manual Version 4, chapter 10. For example, documents such at the Implementation Guidance and Technical Rationale are both referenced in a Section G of this Reliability Standard, but the Reference Manual states these documents should be in Section E: Associated Documents.

Additionally, the Compliance language in Section C does not appear to be the most up-to-date language. The most up-to-date language should be used in the revised Reliability Standard.

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The Implementation Plan has been moved to Section F (Associated Documents). The SDT will clean up the References during Phase II of this project.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
DTE supports NAGF's comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to NAGF's comment.	
Josh Combs - Black Hills Corporation – 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA) and Members	
Answer	
Document Name	
Comment	

It is not clear why the Glencoe Light SAR was drafted independently from the IRPTF SAR, when both were approved at the same time. Some degree of communication of the SDT's plan would be beneficial. Since the proposed changes here are administrative, while the IRPTF's changes are more technical, we believe the Glencoe SAR should not be rushed or pushed through before the IRPTF SAR changes, and if this is a needed change, we welcome details or an explanation if this is only being balloted to get industry input on this issue, but ultimately no new revision will be pushed through until both SARs are addressed.

There has been a widespread problem with R1 of this standard requiring far too many entities to be "notified", which has been an issue for many years. In some regions, only a notification has been required to "remote joint owners", which was an administrative inconvenience (notification was required but the remote joint owner was not required to do anything with that information and was not required to capture any data). In other regions, the "remote joint owner" has apparently been interpreted to be required to capture data – getting back to the inference that receiving a notification under R1.2 somehow conveyed compliance responsibility to the recipient of the notification. The way the standard is written is too complex for a simple issue. Substations have buses and terminal equipment. When we identify a bus, we want voltage measurements on the bus itself, SER on the breakers to the terminal equipment, and FR of the flows on the terminals at that bus location. You can't make measurements without owning PTs, CTs, and relaying or DFR equipment. We suggest that we stop sending notifications to entities who don't own equipment within the substation or who own terminal equipment that isn't required to capture data (as per R3), and let's stop requiring "double-ended" FR and SER data. The problem is using "BES Element" without any clarification. That term has been interpreted to mean the "entire element", and not just the portion that makes up the terminal at the substation.

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT decided to address the Glencoe Light SAR first because required revisions were mostly clarifying in nature. Many in the industry recommended the same approach in their comments to SAR posting. Additionally, both SARs are independent in nature. The intent of revision to R1, Part 1.2 is to address unnecessary notifications that may be occurring today. The SDT defined “directly connected” BES Elements for clarity. Many examples are added in the technical rationale as well.	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	

Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to NPCC Regional Standard Committee's comments.	
Michael Jones - National Grid USA – 1	
Answer	
Document Name	
Comment	

Please consider organizing the sections of PRC-002-4 into the normal organization for reliability standards: Section A - Introduction, Section B - Requirements and Measures, Section C - Compliance, Section D - Regional Variances, Section E - Associated Documents. Please see the Drafting Team Reference Manual.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT will use the latest template for this Standard.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 5 - WECC	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Bobbi Welch - Midcontinent ISO, Inc. – 2	
Answer	
Document Name	
Comment	

MISO supports comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC). In R5, Part 5.3, a new requirement was added for the RC to notify appropriate entities if a BES Element is no longer required to provide DDR data. This goes beyond the scope of the SAR; although the RC may notify parties when certain data is not needed, there is no reliability need or benefit for making this notification a requirement. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. Since R 5.4 requires this to be evaluated every five years, there is no need to further obligate the RC to notify when DDR data is not needed. Therefore, the language, "If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days" should be stricken. This recommendations aligns with scope of the Standards Efficiency Review (SER) Project as it seeks to reduce regulatory obligations that are not essential for reliability and reduce compliance burden. • Overall SER Project Scope ○ Evaluate NERC Reliability Standards using a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard Requirements. Considering that many Reliability Standards have been mandatory and enforceable for 10+ years in North America, this project seeks to identify potential candidate **requirements that are not essential for reliability, could be simplified or consolidated, and could thereby reduce regulatory obligations and/or compliance burden**.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The subject statement is removed.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	
Document Name	
Comment	

In R5, Part 5.3, a new requirement was added for the RC to notify appropriate entities if a BES Element is no longer required to provide DDR data. This goes beyond the scope of the SAR; although the RC may notify parties when certain data is not needed, there is no reliability need or benefit for making this notification a requirement. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. Since R 5.4 requires this to be evaluated every five years, there is no need to further obligate the RC to notify when DDR data is not needed. Therefore, the language, “If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days” should be stricken.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The subject statement is removed.	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	
Document Name	
Comment	
Technical Reference Comments • “Due to the loop created by Line 36 and Line 57, FR data is required for these lines and SER data is required on circuit breakers 3 and 5” o Do not disagree that this should be recorded, but not clear from standard and Glossary of Terms that this is a requirement. The Transmission Line definition is fairly vague and neither the glossary of terms or this standard makes clear that a loop suddenly makes these	

lines transmission lines needing FR versus the example with the singular line. If these lines (36 & 57) were really short, we probably would have considered generator feeds versus lines.

• Rationale for Requirement R2

o Would be helpful to have diagrams showing what breakers feeding elements need and do not need SER or a more detailed statement – for example: Reactor banks, Capacitor banks, Station Service feed at power plant, Reactors off Auto Tertiary windings, etc. The “and” in the standard is something to take notice

• 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”.

o Not sure if second sentence of this statement is true since for multiple generators you can only calculate the total of the generators and not each generator which the statement seems to imply

• Rationale for Requirement R4

o One suggestion would be to point out the need to capture the final cycle of the fault as seen by the fault recorder which can require the need to capture when current/voltage elements drop-out and not just pick up (for longer faults)

Likes 0	
Dislikes 0	

Response

Thanks for your comment.

The SDT recognizes that lines 36 and 57 are exclusively used to export power from a generating plant to the transmission system. Hence, the FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5.

F Examples in Figures 9, 10 and 11 are added to technical rationale and show BES Elements directly connected to an identified BES bus that are required to have SER/FR data.

In case of multiple generators, it may not be necessary to calculate contribution from each generator as far as total contribution is known.

Standards Announcement

Project 2021-04 Modifications to PRC-002

Formal Comment Period Open through July 25, 2022
Ballot Pools Forming through July 8, 2022

Now Available

A formal comment period for **Project 2021-04 Modifications to PRC-002**, is open through **8 p.m. Eastern, Monday, July 25, 2022** for the following standard and implementation plan:

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements
- Implementation Plan

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Thursday, July 8, 2022.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the standard and implementation plan, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **July 15 - 25, 2022**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-04 Modifications to PRC-002” in the Description Box.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/250)
Ballot Name: 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 IN 1 ST
Voting Start Date: 7/15/2022 12:01:00 AM
Voting End Date: 7/25/2022 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 253
Total Ballot Pool: 290
Quorum: 87.24
Quorum Established Date: 7/25/2022 3:00:21 PM
Weighted Segment Value: 66.9

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	81	1	41	0.603	27	0.397	0	4	9
Segment: 2	7	0.4	1	0.1	3	0.3	0	0	3
Segment: 3	67	1	39	0.65	21	0.35	0	3	4
Segment: 4	15	1	10	0.833	2	0.167	0	1	2
Segment: 5	68	1	33	0.702	14	0.298	0	6	15
Segment: 6	46	1	27	0.659	14	0.341	1	0	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.5	4	0.4	1	0.1	0	1	0
Totals:	290	5.9	155	3.947	82	1.953	1	15	37

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Sheraz Majid		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Negative	Third-Party Comments
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship		None	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		None	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Affirmative	N/A
1	Western Area Power Administration	Sean Erickson		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		None	N/A
2	Electric Reliability Council of Texas, Inc.	Dana Showalter		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Brendan Baszkiewicz		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya Vannorman	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Arkansas Electric Cooperative Corporation	Alice Wright		Affirmative	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya Vannorman	Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		None	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Buckeye Power, Inc.	Ryan Strom		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lower Colorado River Authority	Teresa Krabe	Wesley Maurer	Affirmative	N/A
5	National Grid USA	Robin Berry		None	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	John Cook	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Marty Watson		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		None	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		None	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Anirudh Bhimireddy		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Negative	No Comment Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Pam Syrjala		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 290 of 290 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/250)
Ballot Name: 2021-04 Modifications to PRC-002 | Draft 1 Implementation Plan IN 1 OT
Voting Start Date: 7/15/2022 12:01:00 AM
Voting End Date: 7/25/2022 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 253
Total Ballot Pool: 287
Quorum: 88.15
Quorum Established Date: 7/25/2022 2:43:40 PM
Weighted Segment Value: 75.89

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	81	1	42	0.636	24	0.364	0	6	9
Segment: 2	7	0.1	1	0.1	0	0	0	3	3
Segment: 3	67	1	42	0.712	17	0.288	0	5	3
Segment: 4	13	1	10	0.909	1	0.091	0	1	1
Segment: 5	67	1	33	0.733	12	0.267	0	8	14
Segment: 6	46	1	29	0.707	12	0.293	0	1	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.3	3	0.3	0	0	0	3	0
Totals:	287	5.4	160	4.098	66	1.302	0	27	34

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		Affirmative	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Sheraz Majid		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Negative	Third-Party Comments
1	Long Island Power Authority	Isidoro Behar		Negative	Third-Party Comments
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship		None	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		None	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Affirmative	N/A
1	Western Area Power Administration	Sean Erickson		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		None	N/A
2	Electric Reliability Council of Texas, Inc.	Dana Showalter		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Brendan Baszkiewicz		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya Vannorman	Affirmative	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Orlando Utilities Commission	Ballard Mutters		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Austin Energy	Tony Hua		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya Vannorman	Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		None	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Buckeye Power, Inc.	Ryan Strom		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Negative	Comments Submitted
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Negative	Third-Party Comments
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe	Wesley Maurer	Affirmative	N/A
5	National Grid USA	Robin Berry		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	John Cook	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Marty Watson		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		None	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Lisa Martin		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		Negative	Third-Party Comments
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Anirudh Bhimireddy		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Pam Syrjala		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Seminole Electric Cooperative, Inc.	David Reinecke		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 287 of 287 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/250)
Ballot Name: 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 | Non-binding Poll IN 1 NB
Voting Start Date: 7/15/2022 12:01:00 AM
Voting End Date: 7/25/2022 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 238
Total Ballot Pool: 278
Quorum: 85.61
Quorum Established Date: 7/25/2022 4:12:23 PM
Weighted Segment Value: 69.1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	33	0.647	18	0.353	17	9
Segment: 2	6	0.1	1	0.1	0	0	3	2
Segment: 3	64	1	29	0.644	16	0.356	14	5
Segment: 4	14	0.9	8	0.8	1	0.1	3	2
Segment: 5	68	1	30	0.769	9	0.231	13	16
Segment: 6	43	1	19	0.655	10	0.345	8	6
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.4	3	0.3	1	0.1	2	0
Totals:	278	5.4	123	3.916	55	1.484	60	40

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Colorado Springs Utilities	Mike Braunstein		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Steve Ritscher		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Sheraz Majid		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Nurul Abser		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Comments Submitted
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Matt Thompson		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		None	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
1	Western Area Power Administration	Sean Erickson		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Dana Showalter		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Abstain	N/A
3	Avista - Avista Corporation	Scott Kinney		Abstain	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Brendan Baszkiewicz		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya Vannorman	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Hydro One Networks, Inc.	Paul Malozewski		Affirmative	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Nebraska Public Power District	Tony Eddleman		Negative	Comments Submitted
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		None	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Adam Menendez		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	Austin Energy	Tony Hua		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya Vannorman	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	Affirmative	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Buckeye Power, Inc.	Ryan Strom		Abstain	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe	Wesley Maurer	Affirmative	N/A
5	National Grid USA	Robin Berry		None	N/A
5	NB Power Corporation	David Melanson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		None	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	John Cook	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Marty Watson		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		None	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		None	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Justin Kuehne		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Lisa Martin		Abstain	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson		Negative	Comments Submitted
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Anirudh Bhimireddy		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet	James Mearns	Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Pam Syrjala		Affirmative	N/A
6	Santee Cooper	Glenda Horne		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	David Reinecke		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		None	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Negative	Comments Submitted
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal comment period with ballot	06/09/2022 – 07/15/2022
45-day formal or informal comment period with additional ballot	09/26/2022 – 11/09/2022
10-day final ballot	12/09/2022 – 01/16/2023
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
5. **Effective Date:** 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-002-4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[1] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-4, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected 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]*

[1] For the purposes of this standard, “directly connected” BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

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 directly 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 100 kV 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 Reliability Coordinator 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 Reliability Coordinator'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.

5.4. Re-evaluate all BES Elements under its purview 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.

M5. The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator, 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 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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 Enforcement Program:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None.

Violation Severity Levels

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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar	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 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 owners that their BES Elements require SER or FR data by greater than	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	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 number of specified 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 electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified 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 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 Elements and the number of specified electrical	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 electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	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 Reliability Coordinator 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 Reliability Coordinator 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.	The Reliability Coordinator 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 Reliability Coordinator 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	The Reliability Coordinator 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 Reliability Coordinator 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	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator 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 Requirement R7, Parts 7.1 through 7.4 that covers	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.

			more than 80 percent, but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	70 percent, but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	60 percent, but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
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	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner failed to have time synchronization per

			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.	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.	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.	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 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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

			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, 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, 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, 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 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.

R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-4: Implementation Plan.

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.

NERC Reliability Standard PRC-002-4: Technical Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	TBD	TBD	Revised under Project 2021-04

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.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

<u>If the list has more than 11 BES buses:</u> 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[2]

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

[2] "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

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	06/09/2022 – 07/15/2022
45~~XX~~-day formal or informal comment period with additional ballot	09/26~~09~~/2022 – 11~~0~~/09~~17~~/2022
10~~XX~~-day final ballot	12/09/2022 – 01/16/2023
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements

2. **Number:** PRC-002-~~3~~4

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

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Owner

   4.1.3. Generator Owner

5. **Effective Date:** 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-~~3~~4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[1] to those BES buses, ~~if any, within 90-calendar days of completion of Part 1.1,~~ that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have ~~require~~ SER ~~data and/~~or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

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 for Requirement R1, Part 1.1 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-~~3~~4, Attachment 1;~~,~~ has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3. ~~The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.~~

[1] For the purposes of this standard, "directly connected" BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly 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 directly 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 Reliability Coordinator 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 Reliability Coordinator'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 under its purview 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 Reliability Coordinator 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 Reliability Coordinator 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
○ 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 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 Reliability Coordinator, 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.~~

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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 Enforcement Program:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Violation Severity Levels

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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10-calendar days but less than or equal to 20-calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20-calendar days but less than or equal to 30-calendar days.	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 that their BES Elements require SER or FR data by 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 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 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 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 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 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 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 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	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	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	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.

			properties as specified in Requirement R4.	recording properties as specified in Requirement R4.	total recording properties as specified in Requirement R4.	
R5.	Long-term Planning	Lower	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10-calendar days or less.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10-calendar days but less than or equal to 20-calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30-calendar days. OR

						The Reliability Coordinator 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 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	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	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	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.

			determined in Requirement R5.	determined in Requirement R5.	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~~2 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 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 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.	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 than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	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 than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	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 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-	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	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-	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

			calendar days after discovery of the failure.	days after discovery of the failure.	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.	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.
R13.	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

					than or equal to 12 months.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None~~NERC Reliability Standard PRC-002-4: Implementation Plan.

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.

NERC Reliability Standard PRC-002-4: Technical Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	TBD	TBD	Revised under Project 2021-04

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.~~ During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. 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[2]

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

[2] "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

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	06/09/2022 – 07/15/2022
45~~XX~~-day formal or informal comment period with additional ballot	09/26~~09~~/2022 – 11~~0~~/09~~17~~/2022
10~~XX~~-day final ballot	12/09/2022 – 01/16/2023
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-~~3~~4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
5. **Effective Date:** 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-~~3~~4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[1] to those BES buses, ~~if any, within 90-calendar days of completion of Part 1.1,~~ that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have ~~require~~ SER ~~data and/~~or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

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 for Requirement R1, Part 1.1 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-~~3~~4, Attachment 1;~~,~~ has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3. ~~The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.~~

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[1] For the purposes of this standard, "directly connected" BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly 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 directly 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 Reliability Coordinator 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 Reliability Coordinator'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 under its purview 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 Reliability Coordinator 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 Reliability Coordinator 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
○ 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 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 Reliability Coordinator, 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.~~

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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 Enforcement Program:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Violation Severity Levels

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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10-calendar days but less than or equal to 20-calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20-calendar days but less than or equal to 30-calendar days.	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 that their BES Elements require SER or FR data by 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 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 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 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 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 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 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 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	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	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	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.

			properties as specified in Requirement R4.	recording properties as specified in Requirement R4.	total recording properties as specified in Requirement R4.	
R5.	Long-term Planning	Lower	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10-calendar days or less.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10-calendar days but less than or equal to 20-calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20-calendar days but less than or equal to 30-calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30-calendar days. OR

						The Reliability Coordinator 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 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	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	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	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.

			determined in Requirement R5.	determined in Requirement R5.	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~~2 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.~~1~~2 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 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.	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 than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	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 than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	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 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-	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	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-	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

			calendar days after discovery of the failure.	days after discovery of the failure.	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.	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.
R13.	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

					than or equal to 12 months.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None~~NERC Reliability Standard PRC-002-4: Implementation Plan.

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.

NERC Reliability Standard PRC-002-4: Technical Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	TBD	TBD	Revised under Project 2021-04

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.~~ During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. 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[2]

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

[2] "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

Requirement	Entity	Implementation
R13	TO | GO	X

Implementation Plan (Draft)

Project 2021-04 Modifications to PRC-002
Reliability Standard PRC-002-4

Applicable Standard(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Requested Retirement(s)

- PRC-002-3 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner
- Generator Owner

General Considerations

This implementation plan provides that Reliability Standard PRC-002-4 will become effective on the later of: (1) the first day of the first calendar quarter following regulatory approval; or (2) the effective date of PRC-002-3.[1] Additional time to implement this version of Reliability Standard PRC-002-4 is not provided because:

- the revisions to Requirements R1, R3, and R5 are clarifying in nature, and
- the new Requirement R13 simply relocates implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself, and clarifies the implementation time, which was "three years" in the PRC-002-2 implementation plan, to "three calendar years."[2]

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard or as otherwise provided for by the applicable governmental authority; **or** (2) the effective date of PRC-002-3.

[1] In the latter case, Reliability Standard PRC-002-4 will supersede PRC-002-3 prior to it ever becoming effective.
[2] PRC-002-2 and PRC-002-3, Implementation Plans: "Entities shall be 100 percent compliant with new BES [Bulk Electric System] Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator."

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction; **or** (2) the effective date of PRC-002-3.

Retirement Date

The version of Reliability Standard PRC-002 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-002-4.

Prior Implementation Plan

The following element of the Implementation Plan for PRC-002-3 is incorporated herein and modified in case PRC-002-3 is superseded by PRC-002-4:

Reliability Coordinators in the Eastern Interconnection shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3 or six (6) months of the effective date of PRC-002-4, whichever occurs first.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan (Draft)

Project 2021-04 Modifications to PRC-002
Reliability Standard PRC-002-4

Applicable Standard(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Requested Retirement(s)

- PRC-002-3 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner
- Generator Owner

General Considerations

This implementation plan provides that Reliability Standard PRC-002-4 will become effective on the later of: (1) the first day of the first calendar quarter following regulatory approval; or (2) the effective date of PRC-002-3.[1] Additional ~~definite~~ time to implement this version of Reliability Standard PRC-002-4 is not ~~specified~~ provided because:

- the revisions to Requirements R1, R3, and R5 are clarifying in nature, and
- the new Requirement R13 simply relocates ~~the amount of~~ implementation time prescribed in the PRC-002-2 Implementation Plan to the ~~new Requirement R13~~standard itself, and clarifies the implementation time, which was "three years" in the PRC-002-2 implementation plan, to "three calendar years."~~.~~[2]

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard or as otherwise provided for by the applicable governmental authority; **or** (2) the effective date of PRC-002-3.

[1] In the latter case, Reliability Standard PRC-002-4 will supersede PRC-002-3 prior to it ever becoming effective.

[2] PRC-002-2 and PRC-002-3, Implementation Plans: "Entities shall be 100 percent compliant with new BES [Bulk Electric System] Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator."

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction; **or** (2) the effective date of PRC-002-3.

Retirement Date

The version of Reliability Standard PRC-002 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-002-4.

Prior Implementation Plan

The following element~~s~~ of the Implementation Plan for PRC-002-3 ~~are~~is incorporated herein and modified in case PRC-002-3 is superseded by ~~reference and shall remain applicable to~~ PRC-002-4~~.~~:

Reliability Coordinators in the Eastern Interconnection shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3 or six (6) months of the effective date of PRC-002-4, whichever occurs first.

Unofficial Comment Form

Project 2021-04 Modifications to PRC-002

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-04 Modifications to PRC-002** by **8 p.m. Eastern, November 9, 2022.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Ben Wu (via email), or at 404-446-9618.

Background Information

Requirement R1, Part 1.2 infers that the notified BES Element owner is required to have FR data without regard to the identified BES bus owner having a connected BES Element for which FR data would be required for an applicable transformer or transmission line. By virtue of this notification, the transformer or transmission line BES Element owner is burdened with an obligation to have FR data and implicitly obligates these transformer or transmission line BES Element owners to either:

1. Work with other BES Element (i.e., circuit breaker) owners to provide the data and data recording specification for which the transformer or transmission line owners must rely on for compliance, or
2. Install its own equipment that is duplicative to the identified BES Bus recording equipment.

The goal of the proposed project is to clarify the necessary notifications in Requirement R1, Part 1.2 relative to FR data, and clearly identify the BES Element owners that need to have FR data for transformers and transmission lines with the associated identified bus.

Questions

1. Do you agree with the revisions to Requirement 1?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with including the implementation plan information in proposed Requirement R13?

   ☐ Yes
   ☐ No

   Comments:

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002-3

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. Each requirement is assigned a VRF and a VSL. 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 in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

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.

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect 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
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs 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 VRF 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.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

PRC-002-4

VRF Justification for PRC-002-4, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

VSL Justifications for PRC-002-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less).
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do 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 VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-4, Requirement R2
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R2
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R3
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R3
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R4
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R4
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	OR The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days but less than or equal to 20 calendar days.	OR The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

VSL Justifications for PRC-002-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less).
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-4, Requirement R5	
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 VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-4, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R6
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R7
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R7
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R8
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R8
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R9
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R9
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R10
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R10
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R11
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R11
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justifications for PRC-002-4, Requirement R13	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R13 is consistent with those of other requirements to have DDR, SER, or FR data in the proposed Reliability Standard.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-002-4, Requirement R13			
Lower	**Moderate**	**High**	**Severe**
	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

VSL Justifications for PRC-002-4, Requirement R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-4, Requirement R13	
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	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002-3

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. Each requirement is assigned a VRF and a VSL. 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 in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

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.

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect 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

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs 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 VRF 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.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

PRC-002-4

VRF Justification for PRC-002-4, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
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 that their BES Elements require SER or FR data by 10 calendar days or less. ~~OR~~	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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

~~The Transmission Owner as directed by Requirement R1, Part 1.2 did not notify the other owners that their BES Elements do not require SER or FR data within 90 calendar days.~~			

VSL Justifications for PRC-002-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less). ~~Consistent with the proposed revisions to the associated requirement, the SDT also added languge to the Lower VSL to address the instance where the Transmission Owner as directed by Requirement R1, Part 1.2 did not notify the other owners that their BES Elements do not require SER or FR data within 90 calendar days.~~
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	The proposed VSLs are not binary and do 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	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.

VSL Justifications for PRC-002-4, Requirement R1	
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	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-4, Requirement R2
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R2
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R3
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R3
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R4
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R4
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less. ~~OR~~ ~~The Reliability Coordinator as directed by Requirement R5, Part 5.3 did not notify the owners that their BES Elements do not require DDR data within 90 calendar days.~~	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

VSL Justifications for PRC-002-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less). ~~Consistent with the proposed revisions to the associated requirement, the SDT also added languge to the Lower VSL to address the instance where the Reliability Coordinator as directed by Requirement R5, Part 5.3 did not notify the owners that their BES Elements do not require DDR data within 90 calendar days.~~
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do 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 VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-4, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R6
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R7
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R7
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R8
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R8
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R9
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R9
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R10
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R10
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R11
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R11
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justifications for PRC-002-4, Requirement R13	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R13 is consistent with those of other requirements to have DDR, SER, or FR data in the proposed Reliability Standard.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-002-4, Requirement R13			
Lower	**Moderate**	**High**	**Severe**
~~The Transmission Owner or Generator Owner had SER data for more than 75 percent, but less than 100 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner had FR data for more than 75 percent, but less than 100 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner had DDR data for more than 75 percent, but less than 100 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.~~	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.~~Transmission Owner or Generator Owner had SER data for more than 50 percent, but less than 75 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner had FR data for more than 50 percent, but less than or equal to 75 percent of the BES buses identified during the re-~~	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.~~The Transmission Owner or Generator Owner had SER data for more than 25 percent, but less than 50 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner had FR data for more than 25 percent, but less than or equal to 50 percent of the BES buses identified during the re-~~	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.~~The Transmission Owner or Generator Owner had SER data for less than or equal to 25 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner had FR data for less than or equal to 25 percent of the BES buses identified during the re-evaluation per Requirement R1, Part 1.3.~~ ~~OR~~

	~~evaluation per Requirement R1, Part 1.3.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner had DDR data for more than 50 percent, but less than or equal to 75 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.~~	~~evaluation per Requirement R1, Part 1.3.~~ ~~OR~~ ~~The Transmission Owner or Generator Owner had DDR data for more than 25 percent, but less than or equal to 50 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4.~~	~~The Transmission Owner or Generator Owner had DDR data for less than or equal to 25 percent of the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4~~

VSL Justifications for PRC-002-4, Requirement R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the 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	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore,

VSL Justifications for PRC-002-4, Requirement R13	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	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	Each VSL is based on a single violation and not cumulative violations.

Technical Rationale for Reliability Standard PRC-002-4

April 2022

PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator 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 Requirement 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 Disturbance Monitoring Standard Drafting Team'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-002-4, 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.

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.
5. 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 the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.
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.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B and C are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1600 MVA, 1500 MVA and 1550 MVA respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1550 MVA, 1675 MVA and 1600 MVA respectively. The bus B is the one with highest maximum three phase short circuit MVA now. The three phase short circuit MVA of bus B is within 15% of the three phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1500 MVA, 1750 MVA and 1650 MVA respectively. The three phase short circuit MVA of bus B is greater than 15% of three phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

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 requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of “directly connected” BES Elements are notified. For the purposes of this standard, “directly connected” BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 1 and 2 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

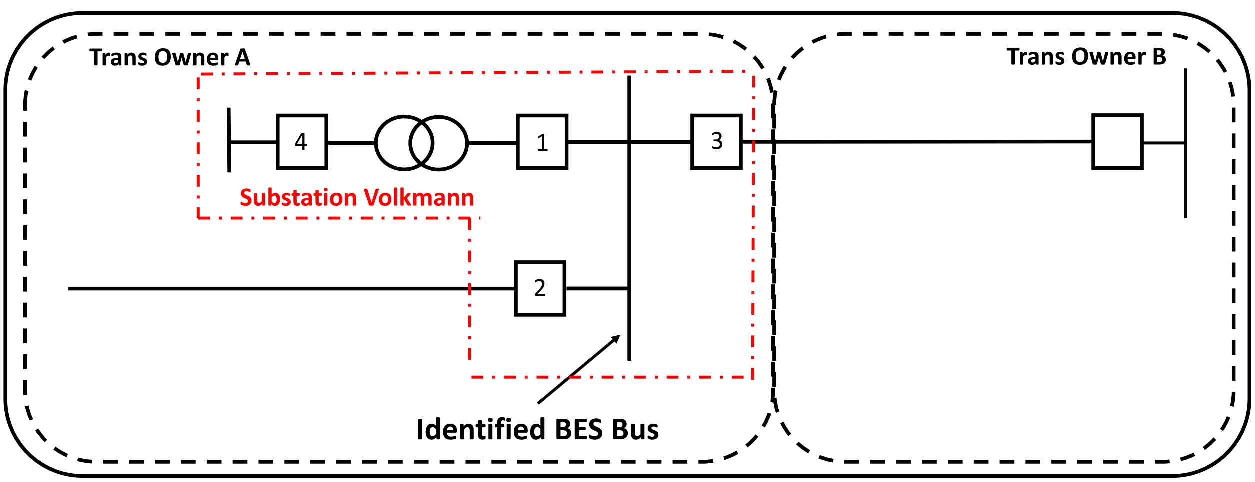

Figure 1: Straight Bus Configuration – Single Owner

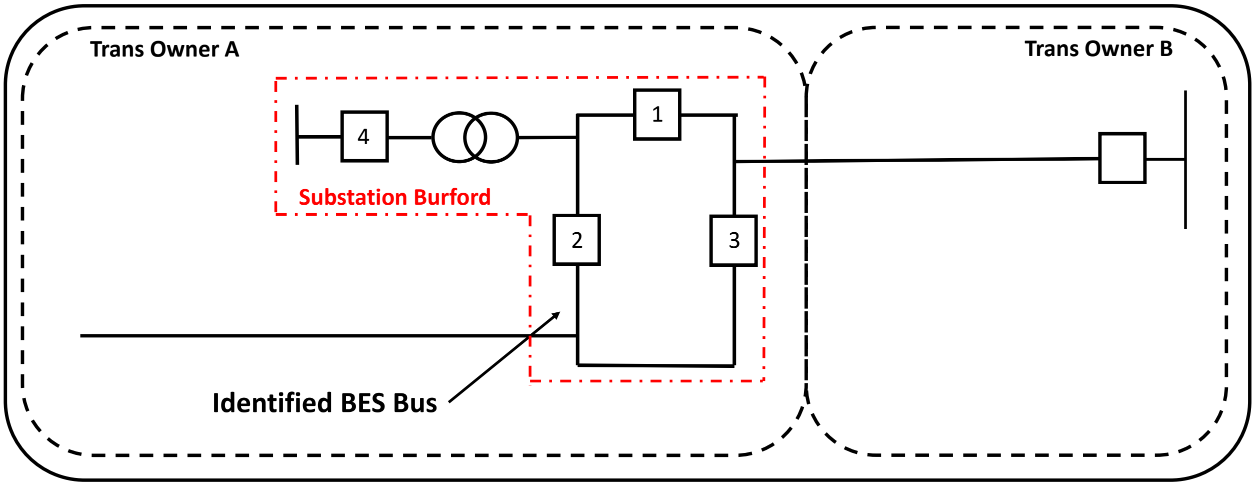

Figure 2: Ring Bus Configuration – Single Owner

Figures 3 and 4 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

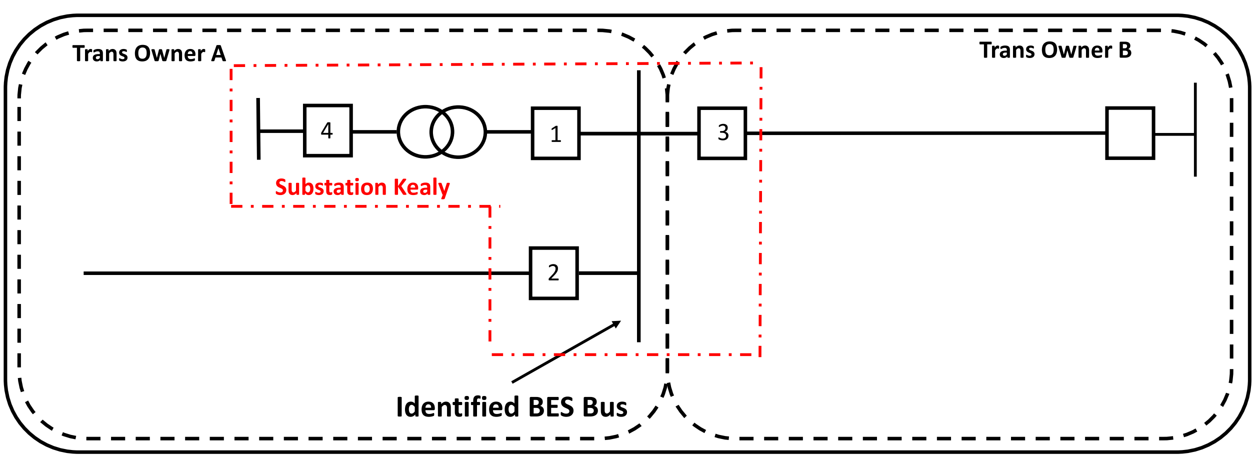

Figure 3: Straight Bus Configuration – Multiple Owners

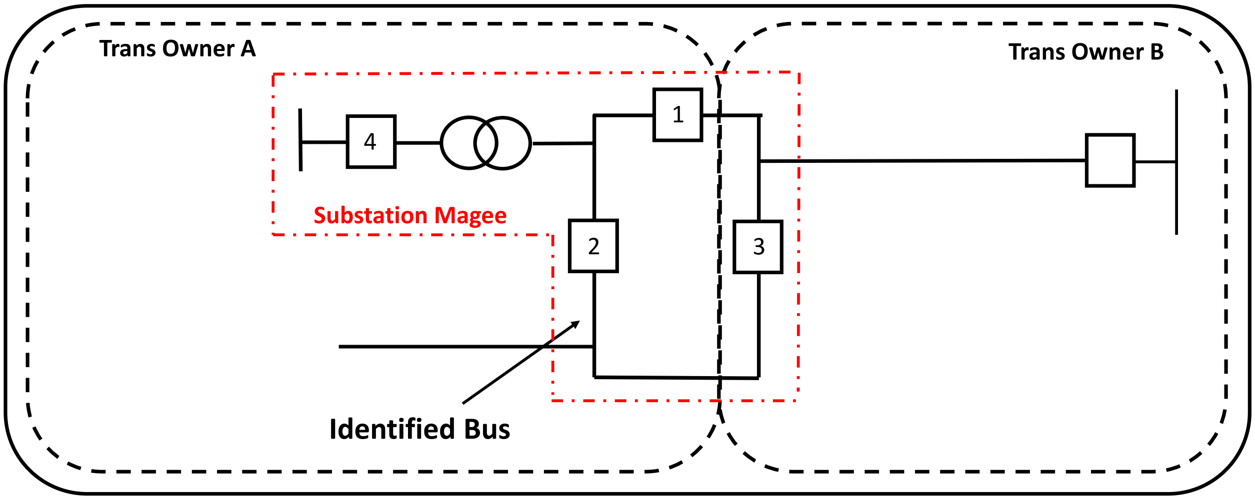

Figure 4: Ring Bus Configuration – Multiple Owners

For examples in Figures 3 and 4, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 5 shows an example with a generator interconnection. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

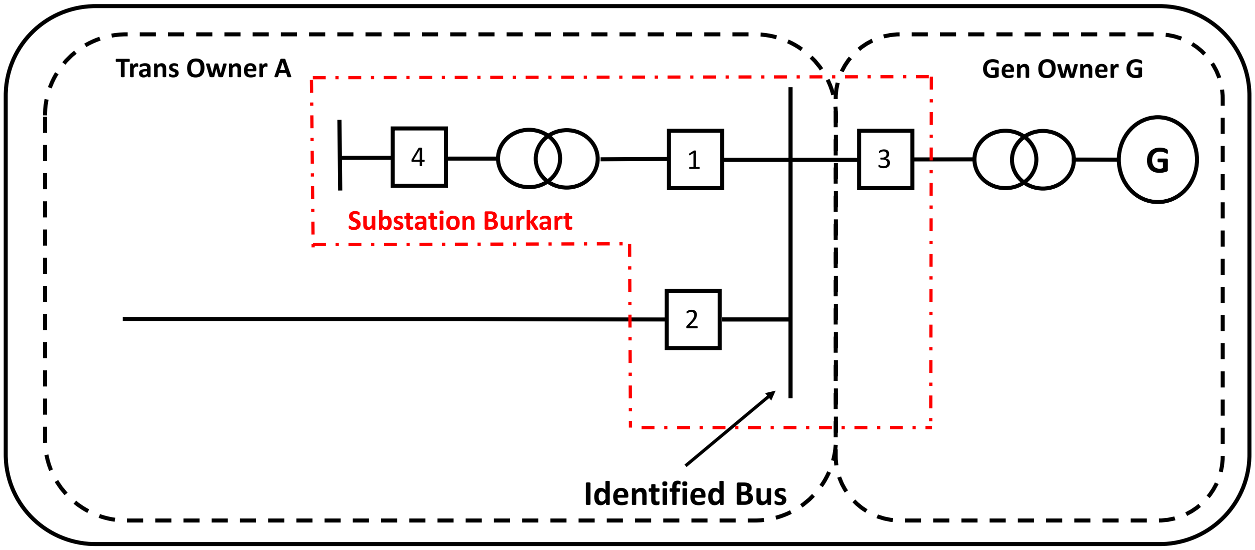

Figure 5: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 6, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

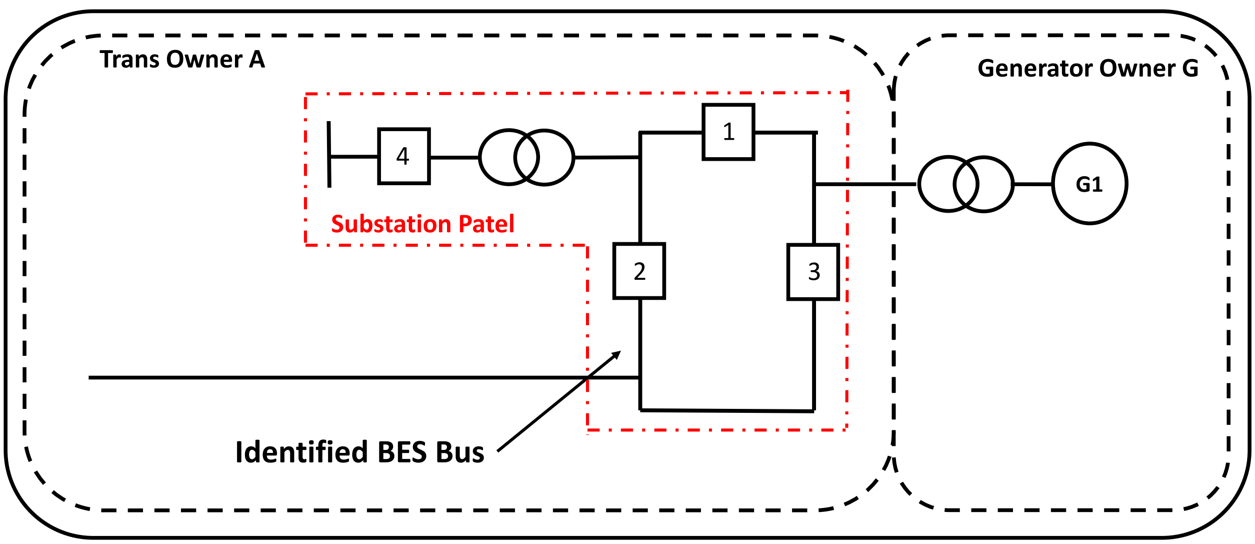

Figure 6: Generator Interconnection to Ring Bus

Figure 7 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical

bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

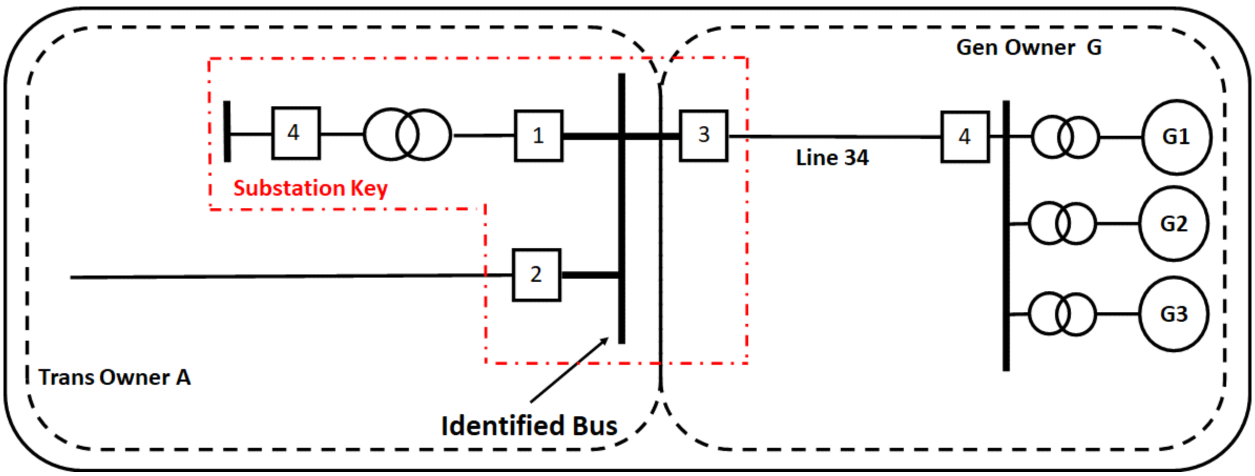

Figure 7: Generator Interconnection via Line 34

Figure 8 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3 and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

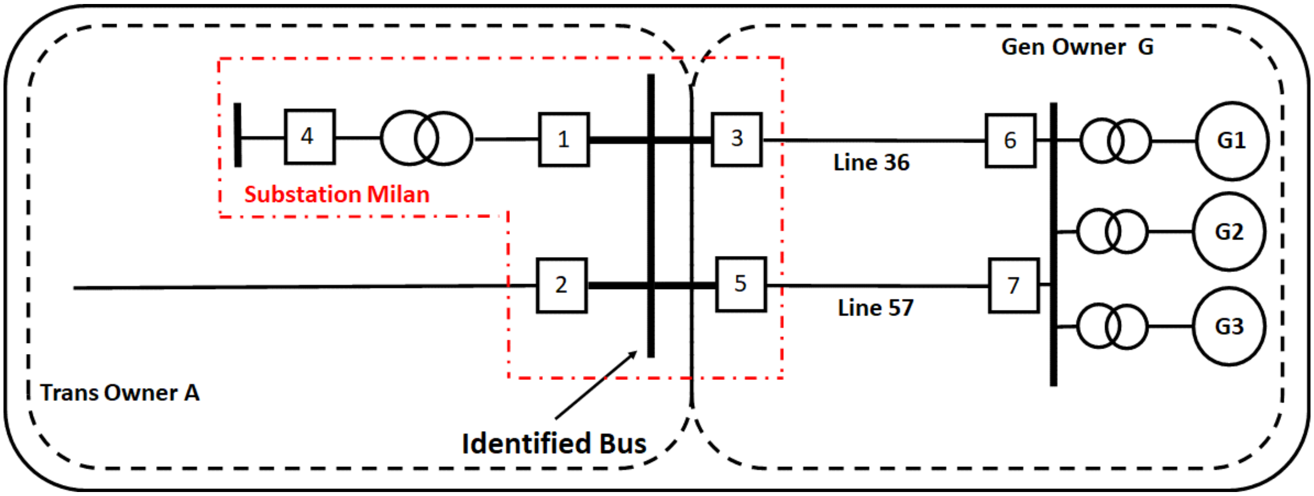

Figure 8: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification_TransmissionOwnerB

Greetings,

In accordance with NERC Standard PRC-002-4, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

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.

Rationale for Requirement 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 directly connected to a BES bus. Change of state of circuit breaker position and 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.

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.

Examples in Figures 9, 10 and 11 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement 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.

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 directly 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 directly 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.

Examples in Figures 9, 10, and 11 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

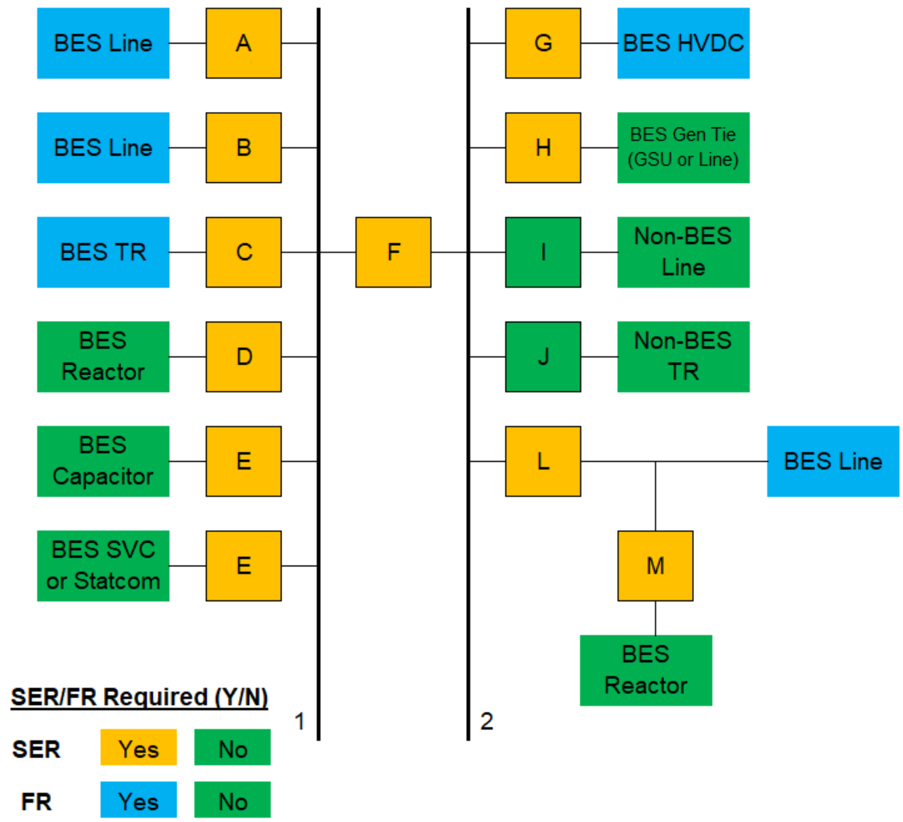

Figure 9: Straight BES Buses

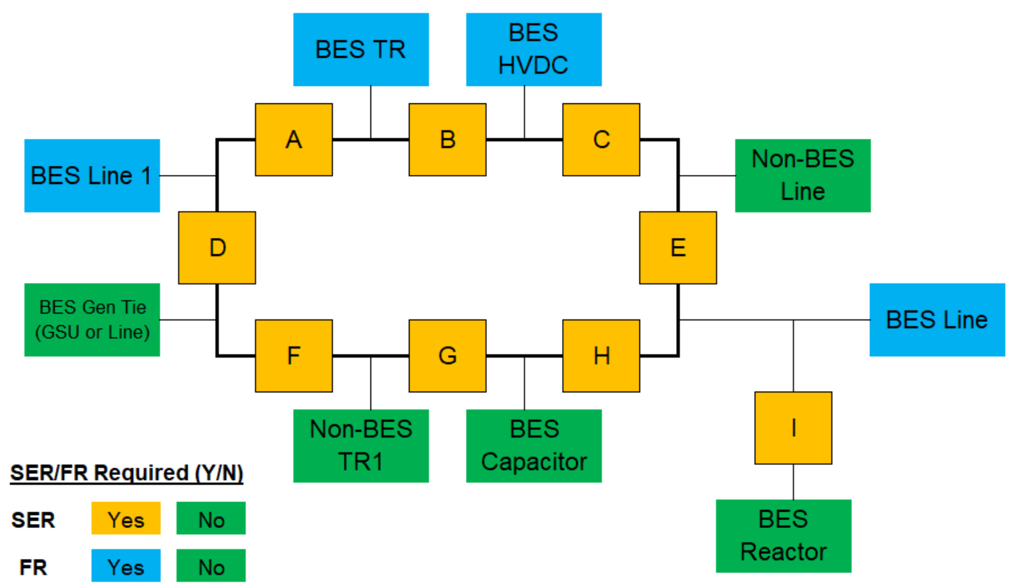

Figure 10: Ring BES Bus

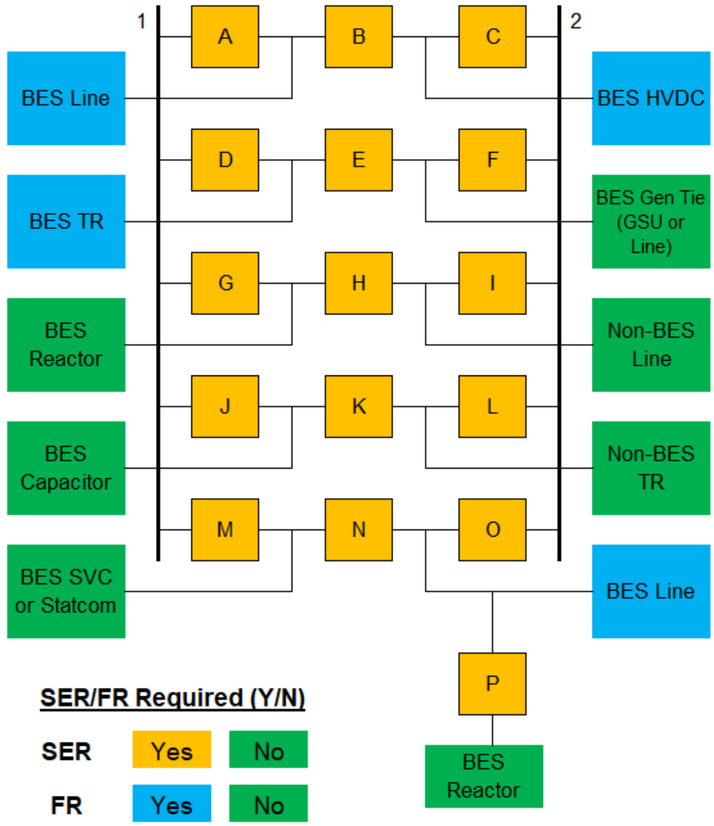

Figure 11: Breaker and Half BES Bus

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.

<u>Voltage Recordings</u>
Voltages are to be recorded or accurately determined at applicable BES buses

Rationale for Requirement 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.

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.

Rationale for Requirement 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 Reliability Coordinator 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 Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator 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 Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator 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 Reliability Coordinators, each Reliability Coordinator 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 Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator 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 Reliability Coordinators. It is intended that each Reliability Coordinator 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.

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 Reliability Coordinator 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 Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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.).

Rationale for Requirement 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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

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 Reliability Coordinator 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-002-4 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.

Rationale for Requirement 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 eitherthe 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.

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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement 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).

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.

Rationale for Requirement 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.

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.

Rationale for Requirement 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.

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 one millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement 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 11.2, 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. A10-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.

This requirement directs the applicable entities, upon requests from the Reliability 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 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 11.2 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 11.1 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 synchrophasor 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.

Rationale for Requirement 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.

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.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Technical Rationale for Reliability Standard PRC-002-4

April 2022

PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator 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 Requirement 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 Disturbance Monitoring Standard Drafting Team'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-002-4, 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.

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.
5. 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 the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.
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.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B and C are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1600 MVA, 1500 MVA and 1550 MVA respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1550 MVA, 1675 MVA and 1600 MVA respectively. The bus B is the one with highest maximum three phase short circuit MVA now. The three phase short circuit MVA of bus B is within 15% of the three phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1500 MVA, 1750 MVA and 1650 MVA respectively. The three phase short circuit MVA of bus B is greater than 15% of three phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

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. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of "directly connected" BES Elements are notified. For the purposes of this standard, "directly connected" BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 1 and 2 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

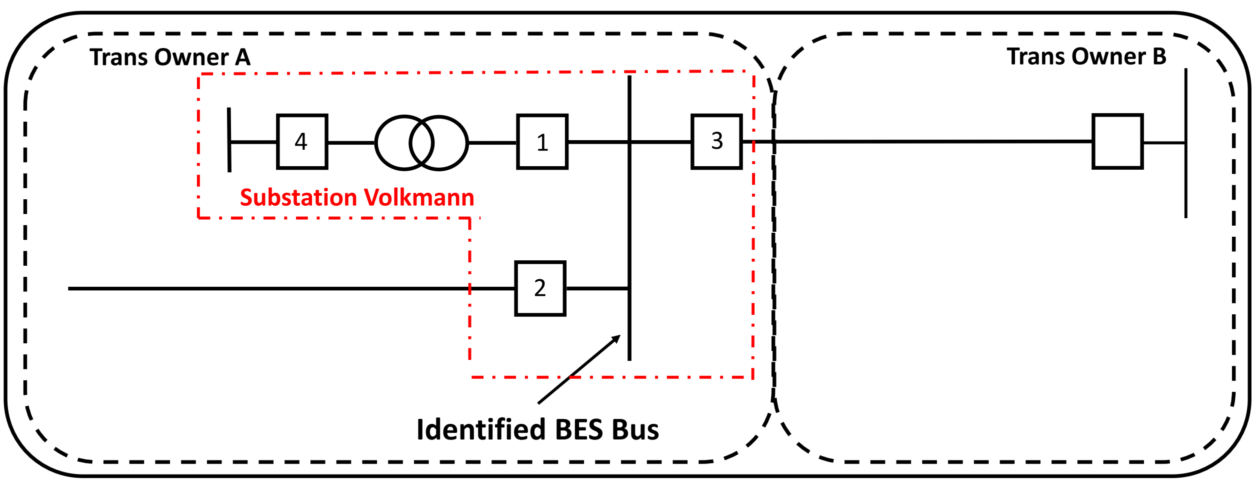

Figure 1: Straight Bus Configuration – Single Owner

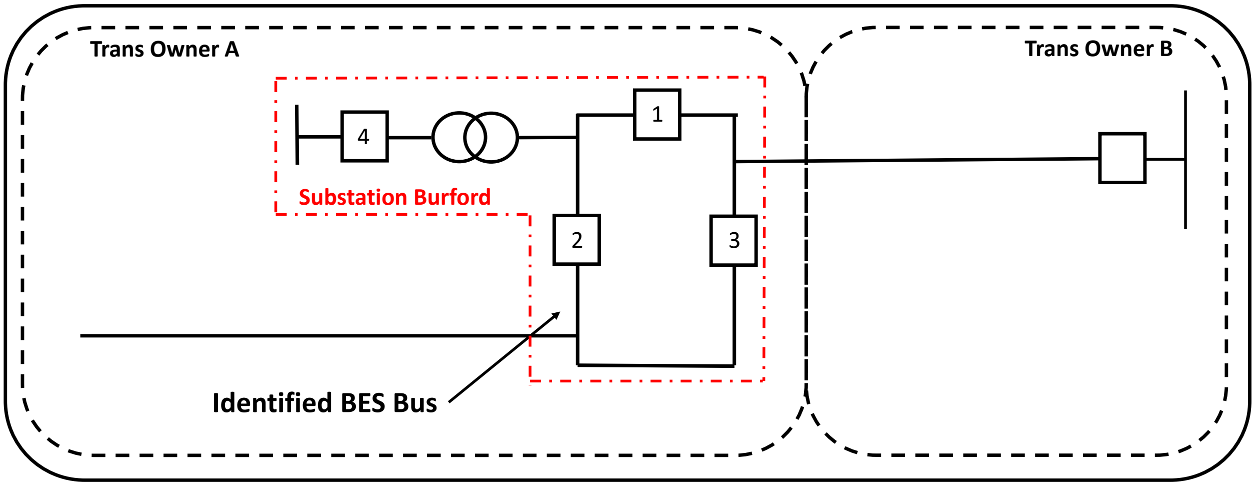

Figure 2: Ring Bus Configuration – Single Owner

Figures 3 and 4 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that ~~of their responsibility to record~~ SER/FR data is required for circuit breaker 3.

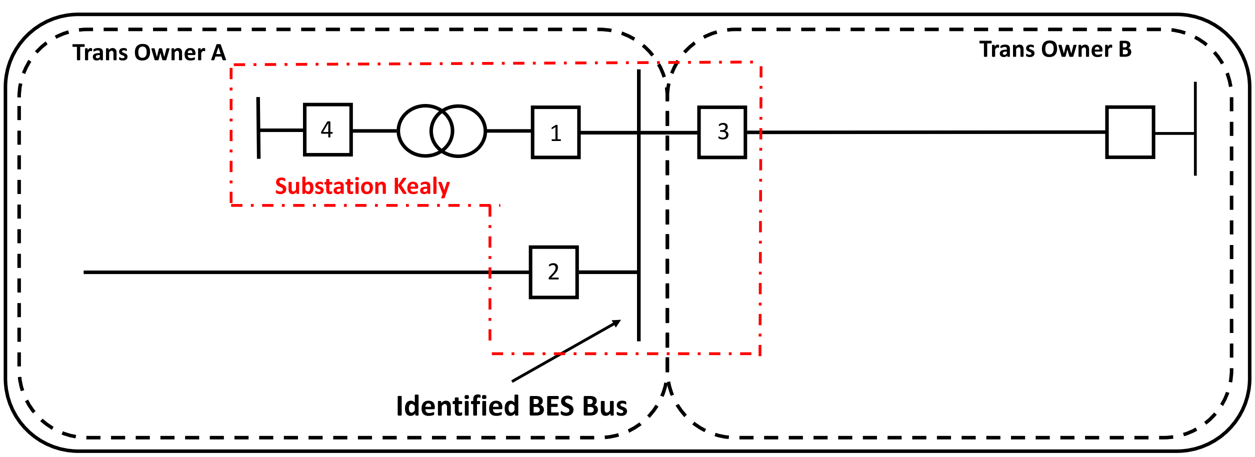

Figure 3: Straight Bus Configuration – Multiple Owners

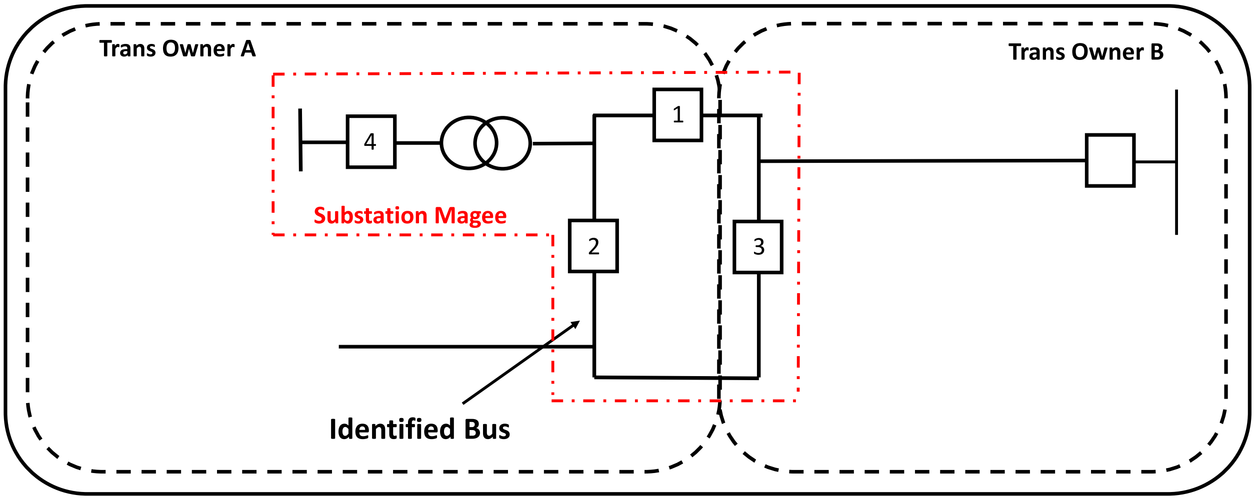

Figure 4: Ring Bus Configuration – Multiple Owners

For examples in Figures 3 and 4, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 5 shows an example with a generator interconnection. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that~~of their responsibility to record~~ SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

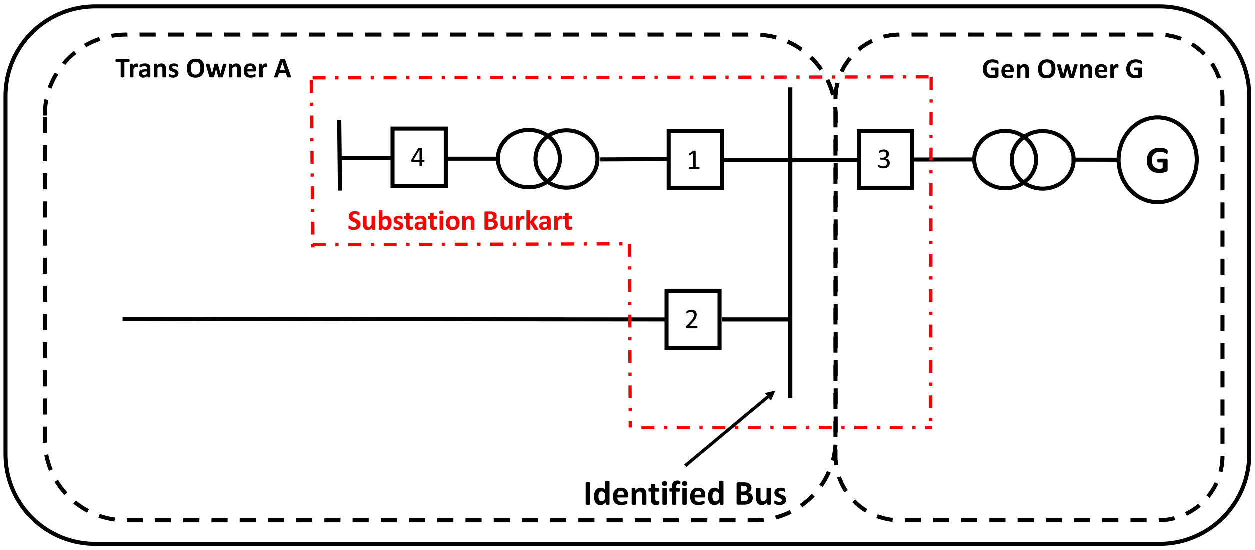

Figure 5: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 6, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

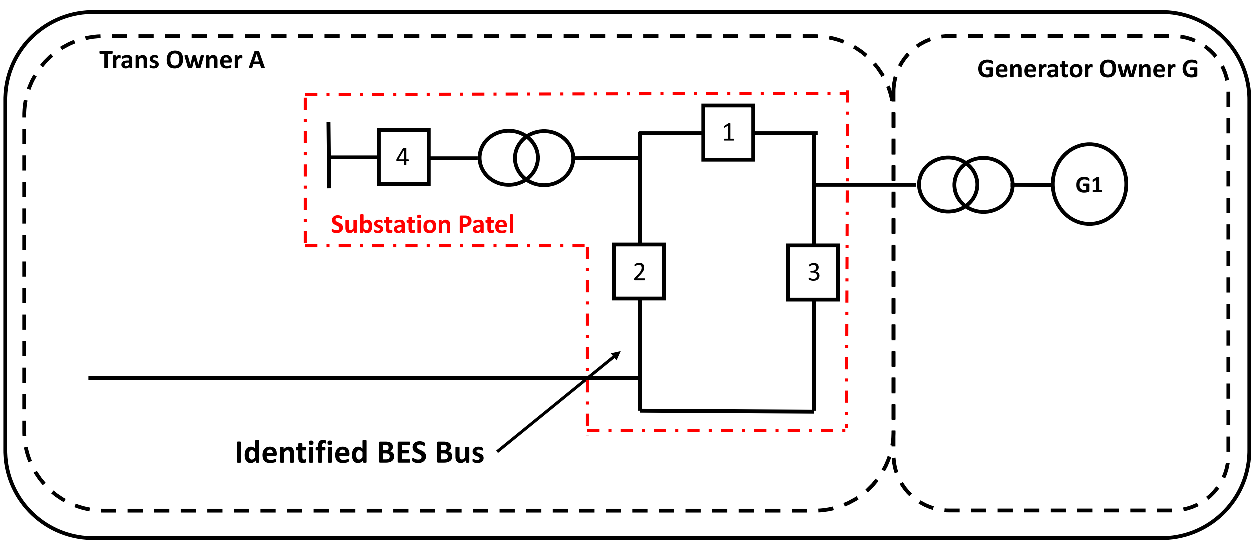

Figure 6: Generator Interconnection to Ring Bus

Figure 7 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that ~~of their responsibility to record~~ SER data ~~for~~ is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

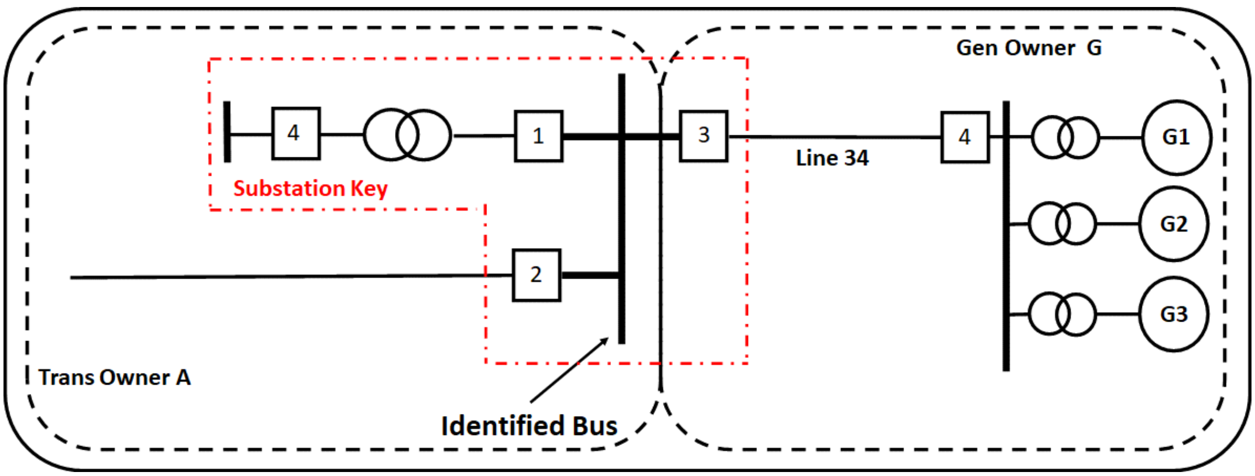

Figure 7: Generator Interconnection via Line 34

Figure 8 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3 and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. ~~Due to the~~ The loop is created by Line 36 and Line 57.~~,~~ These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, ~~and~~ SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER ~~and FR~~ data for circuit breakers 3 and 5, then Generator Owner G must be notified that ~~of their responsibility to record~~ SER ~~and FR~~ data is required for circuit breakers 3 and 5.

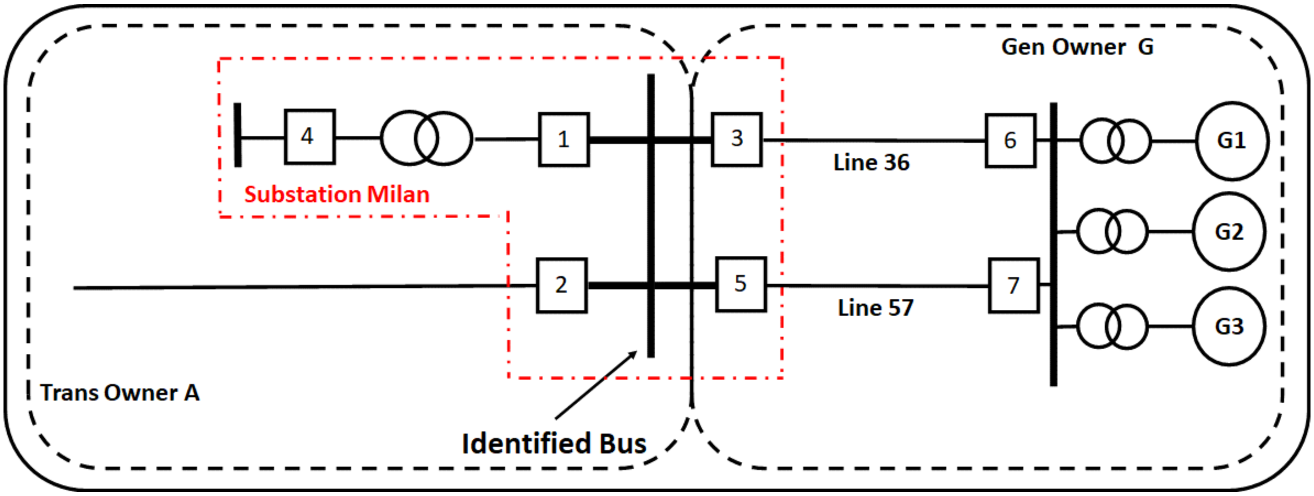

Figure 8: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification TransmissionOwnerB

Greetings,

In accordance with NERC Standard PRC-002-4, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	**Directly connected BES Element owned by Transmission Owner B**	**BES Element Type**	**Data Required**
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

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.

Rationale for Requirement 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 directly connected to a BES bus. Change of state of circuit breaker position and 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.

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.

Examples in Figures 9, 10 and 11 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement 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.

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 directly 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 directly 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.

Examples in Figures 9, 10, and 11 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

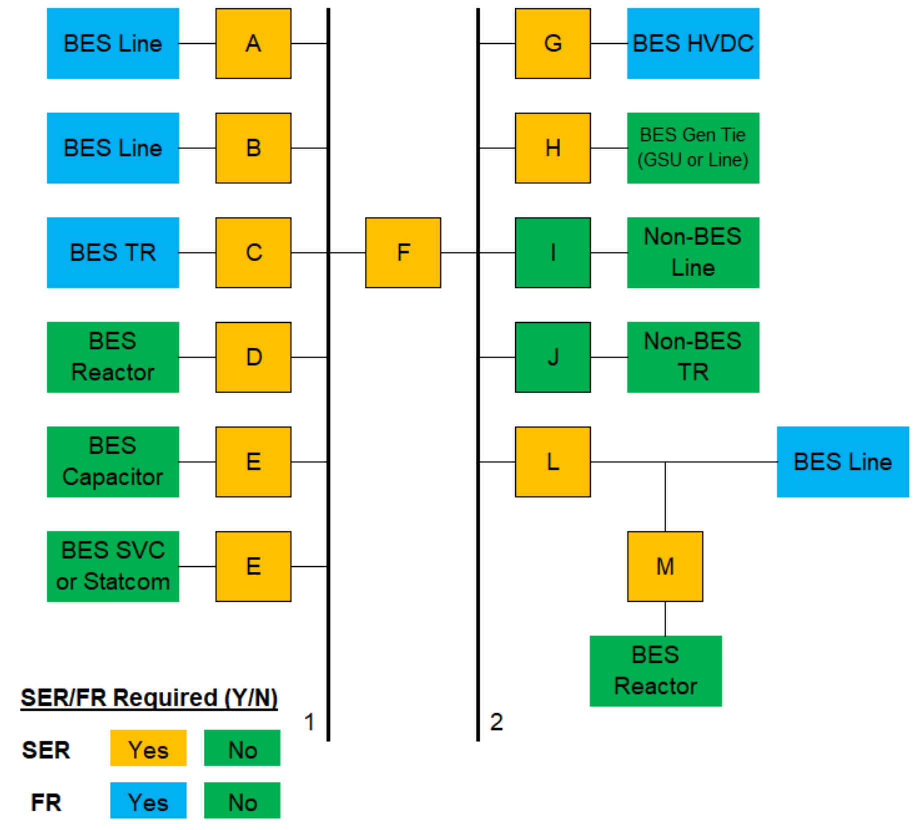

Figure 9: Straight BES Buses

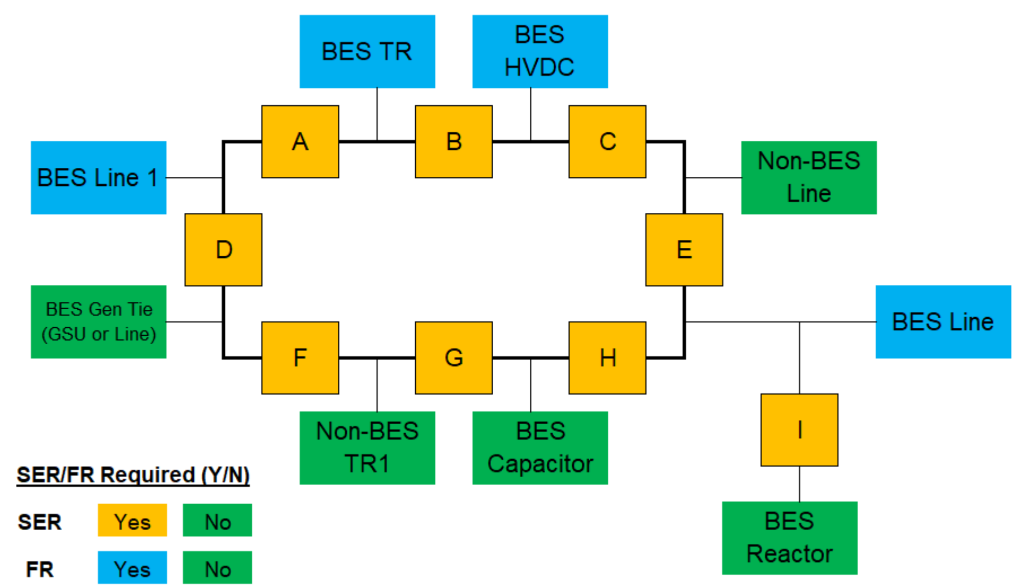

Figure 10: Ring BES Bus

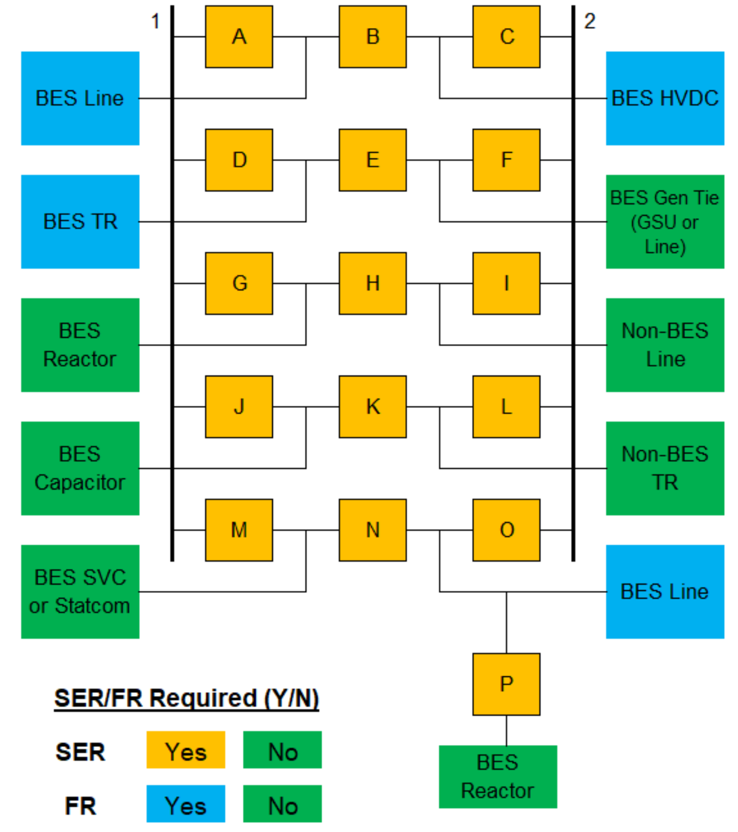

Figure 11: Breaker and Half BES Bus

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

Rationale for Requirement 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.

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 ~~p~~Protection System operations after a fault to determine if a ~~p~~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.

Rationale for Requirement 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 Reliability Coordinator 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 Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator 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 Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator 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 Reliability Coordinators, each Reliability Coordinator 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 Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator 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 Reliability Coordinators. It is intended that each Reliability Coordinator 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.

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 Reliability Coordinator 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 Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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.).

Rationale for Requirement 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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

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 Reliability Coordinator 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-002-4 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.

Rationale for Requirement 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.

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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement 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).

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.

Rationale for Requirement 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.

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.

Rationale for Requirement 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.

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~~ one millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement 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 11.2~~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. A10-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.

This requirement directs the applicable entities, upon requests from the Reliability 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 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~~2 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 11.1~~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 synchrophasor 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.

Rationale for Requirement 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.

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.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving~~following a~~ notification by the Transmission Owner or the Reliability Coordinator ~~to another Transmission Owner/Generator Owner~~ is ~~the same amount of~~more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving ~~following a~~ notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2021-04 Modifications to PRC-002

Formal Comment Period Open through November 9, 2022

Now Available

A 45-day formal comment period for **Project 2021-04 Modifications to PRC-002**, is open through **8 p.m. Eastern, Wednesday, November 9, 2022** for the following standard and implementation plan:

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements
- Implementation Plan

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Commenting
Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
Additional ballots for the standard and implementation plan, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 31 – November 9, 2022**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2021-04 Modifications to PRC-002 Observer List" in the Description Box.

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Suite 600, North Tower
Atlanta, GA 30326
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Comment Report

Project Name:	2021-04 Modifications to PRC-002 | Draft 2
Comment Period Start Date:	9/26/2022
Comment Period End Date:	11/10/2022
Associated Ballots:	2021-04 Modifications to PRC-002 | Draft 1 Implementation Plan AB 2 OT 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 | Non-binding Poll AB 2 NB 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 AB 2 ST

There were 46 sets of responses, including comments from approximately 89 different people from approximately 63 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the revisions to Requirement 1?

2. Do you agree with including the implementation plan information in proposed Requirement R13?

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					David Hartman	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5	RF	DTE Energy	patricia ireland	DTE Energy	4	RF
					Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6,7	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO

					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc	2	MRO
					Brett Springfield	Southwest Power Pool Inc.	2	MRO
Tim Kelley	Tim Kelley		WECC	SMUD / BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the revisions to Requirement 1?

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

The Standard Drafting Team (SDT) should consider combining Parts 1.1 and 1.3 (retiring Part 1.3). The SDT should consider whether "fault" should be capitalized in R1, Part 1.1, since it is a defined term in the NERC Glossary of Terms Used in Reliability Standards and is capitalized in Attachment 1. A possible rewording for Part 1.1:

"1.1. Identify BES buses for which sequence of events recording (SER) and **F**ault recording (FR) data is required by using the methodology in PRC-002-4, Attachment 1. **After the initial performance, re-evaluate all BES buses at least once every five calendar years.**"

If Part 1.3 is retired / combined into Part 1.1, then the proposed edit to Attachment 1, Step 7 should also be modified. It could be revised to "During re-evaluation per Requirement R1, **Part 1.1**, if the three phase short circuit…".

R1, Part 1.2, as proposed in Draft 2 doesn't seem to require the Transmission Owner to inform "other owners of BES Elements directly connected to those BES buses" if a BES Element identified in a prior performance of Part 1.1 is not identified as requiring SER or FR data as part of a re-evaluation. This could potentially result in a misinformed PRC-002 compliance obligation to the other owners of those BES Elements. A possible rewording for Part 1.2:

"1.2. Notify the other owners of BES Elements directly connected to those BES buses, that SER or FR data is required for those BES Elements **(or determined not to be required upon a re-evaluation)**, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1."

For footnote 1 (page 3 of the Draft 2 "clean" version), we recommend that "elements" be capitalized since it is capitalized within R1 (part 1.2) and is a defined term in the NERC Glossary of Terms Used in Reliability Standards.

The SDT should consider adding a footnote that identifies the initial effective date of PRC-002-2, R1 (7/1/2016). For Transmission Owners that have maintained their registration as a TO continuously since before 7/1/2016, this is the date that their initial performance of R1 was required.

Likes 0	
Dislikes 0	
Response	

John Daho - MEAG Power - 1 - SERC	
Answer	Yes
Document Name	
Comment	

MEAG Power agrees with revising R1 but further clarification is needed for 1.2 as shown in the technical Rationale. Below is suggested language:-
1.2.1 "Notify the other owners of BES Elements directly connected to those BES buses, that SER or FR data is required for those BES Elements"

1.2.2 “SER or FR data is only required if the Transmission Owner who identified the BES buses in Part 1.1 dos not have SER/or FR data for the BES Elements it doesn’t own.

Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with the revisions.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation has no comments. Kimberly Turco, on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy asks the DT for clarification on R1.3. Per R1.3, would notification be required every five years if the other owner was notified previously. If the other owner was notified previously and the data is currently being monitored, would notification still be required?	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes

Document Name	
Comment	
Minnkota supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) appreciates the opportunity to respond and thanks the drafting team for their efforts. While the changes to R1 do not directly impact SIGE's procedures, SIGE would like to highlight the potential that the revisions may be burdensome on industrial customers and municipalities that may not readily have access to SER or FR data at the time of notification.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Texas RE recommends Footnote 1 be revised to capitalize “elements” as it is a defined term in the NERC Glossary. The Technical Rationale document does capitalize the term.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees with the changes made to Requirement 1 and the associated subparts and is sufficient to clarify when SER and FR notifications are made to “other owners” of BES Elements where SER and FR data is required.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF has no comments.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	

Comment	
Provides notification clarification and lessens duplication in FR/SER data collection implementation.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5 - RF, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro supports the revisions to Requirement R1 as proposed in Draft 2 of PRC-002-4. BC Hydro however is not supportive of the addition of the wording "under its purview" within Requirement R5 Part 5.4 of proposed PRC-002-4, and recommends that this wording be replaced with "within its Reliability Coordinator Area." BC Hydro acknowledges the SDT's response to industry comments on Draft 1 to clarify that "under its purview" and "within its RC Area" have the same intended meaning and BC Hydro supports this interpretation. However, the wording "within its RC Area" is being consistently used in several other Reliability Standards (e.g. IRO-008, IRO-009, IRO-002, IRO-010, IRO-014, IRO-017, FAC-011, FAC-014, COM-001, EOP-006, EOP-010, EOP-011) and helps differentiate from wording such as "its Wide Area", which has a different meaning. Therefore, BC Hydro believes that using the "within its RC Area" reinforces consistency across Reliability Standards and adds clarity that will alleviate the risk of possible misinterpretations. BC Hydro also recommends that the Technical Rationale document be updated to explain this change to the wording of the Requirement R5.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5 - NPCC	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with including the implementation plan information in proposed Requirement R13?

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments, **and additionally OPG suggests the following modification**: "R13…If the equipment was installed prior to the effective date of this standard **or prior to the 5year re-evaluation/notification of newly identified BES Elements for which DDR is required,** and is not capable of continuous recording, triggered records must meet the following:…" The above proposed wording will allow the entities identified, part of a 5year re-evaluation/notification, as owning BES Elements for which DDR is required, to use the already existing installed equipment albeit installed after the effective date of this standard and prior to the 5year re-evaluation/notification.	

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5 - NPCC	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments, **and additionally OPG Suggests the following modification**: "R13…If the equipment was installed prior to the effective date of this standard **or prior to the 5year re-evaluation/notification of newly identified BES Elements for which DDR is required,** and is not capable of continuous recording, triggered records must meet the following:…" The above proposed wording will allow the entities identified, part of a 5year re-evaluation/notification, as owning BES Elements for which DDR is required, to use the already existing installed equipment albeit installed after the effective date of this standard and prior to the 5year re-evaluation/notification.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1 - WECC	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	

R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.

Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
We agree but it must respect Requirement R8 that says that if the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, we can use the existing equipment with the triggers of the 8.1 and 8.2.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Provides implementation clarification to the ongoing re-evaluation and following R1 part 1.3 notification.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF has no comments.	

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

The SDT should consider additional edits to R13, Part 13.1 to clarify applicability. A possible rewording for Part 13.1:

"13.1. Within three (3) calendar years of completing a re-evaluation **under Requirement 1, Part 1.1 (TO)** or receiving notification under Requirement R1, **Part 1.2 (TO or GO)**, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses."

The SDT should also consider possible mis-interpretations of "three (3) calendar years". Based on the *ERO Enterprise CMEP Practice Guide: Implementation of "Annual" and "Calendar Month(s)" in the Reliability Standards* (dated April 19, 2019), a Calendar Year is considered as "beginning on January 1 and ending on December 31". If a notification is received in December, would the second calendar year begin on the adjacent January? The SDT should consider changing this to "within 36 calendar months".

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the implementation plan being included in Requirement R13 given this is an ongoing requirement.

Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	

Comment	
We agree but it must respect R8 that says that if the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, we can use the existing equipment with the triggers of R8.1 and R8.2.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE supports moving the timeframe from the implementation plan to Requirement R13; however, SIGE recommends that the implementation period be amended to “five (5) calendar years”. SIGE believes the three-year implementation period may be too restrictive given set project cycles and several challenges faced by the industry including outage constraints due to capacity shortfalls and long lead-times due to supply chain issues.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	

Comment	
Minnkota supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP thanks the Standards Drafting Team for their consideration of AEP's previous comments, and in changing from a "three year" period of time to have data in response to notification(s) under R1 to a "three calendar year" period under the proposed R13.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Moving the new SER, FR, or DDR element timetable from the Implementation Plan to the standard requirements is the appropriate location.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Moving the new SER, FR, or DDR element timetable from the Implementation Plan to the standard requirements is the appropriate location. Kimberly Turco, on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with locating the Implementation Plan information within Requirement R13 and the clarification it is 3 calendar years.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5 - RF, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy suggests the time-based requirements in R13.1 and R13.2 be increased from three calendar years to five calendar years. There are multiple challenges to implementing a transmission project within a three-year time period, the most prominent being that it could impact the scheduling and implementation of projects underway pursuant to compliance with other standards (e.g., TPL-001). Additionally, Duke Energy operates on a 3-year budget cycle, and a three calendar year requirement would present scheduling issues at the back end of the budget cycle. A five calendar year requirement would eliminate these scheduling and implementation challenges.	
Likes 0	
Dislikes 0	
Response	

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E wishes to thank the Standard Drafting Team (SDT) for their effort and inclusion of our and others' earlier comments in this draft..	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no additional comments.	

Kimberly Turco, on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no additional comments	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
While AEP agrees in principle with the overall efforts of the Standards Drafting Team, we would like to once again express our concern regarding the associated Technical Rationale document. As we shared in our previous comments, Technical Rationale documents are only to assist in the technical understanding of a requirement and/or Reliability Standard, and should not include compliance examples or compliance language. As previously stated,	

AEP believes the examples provided in the proposed Technical Rationale document (especially on pages 4 through 15) go beyond mere technical understanding of the obligations and could possibly be referenced in the determination of compliance of those obligations. As such, we believe it would be more appropriate for this content to be embedded within the standard itself, perhaps as an "Attachment 3."

In future revisions of PRC-002 (i.e. outside of the current project phase), it may be worth considering the following…

1) Generator Owners could benefit from guidance within the standard regarding the thresholds in Step 7 of Attachment 1 and in clearly understanding when those have been met. When these obligations were originally developed, the "top 10 percent" methodology was a sound place to begin, but going forward, more flexibility in this regard would certainly be beneficial.

2) Develop clarity within the standard regarding re-evaluations that result in a site(s) no longer being in scope. Specifically, exactly how much time must pass until those sites may be considered no longer PRC-002 reportable?

Likes 0	
Dislikes 0	

Response

Bret Galbraith - Seminole Electric Cooperative, Inc. - 6

Answer	
Document Name	

Comment

1. Requirement 1.2: The revisions appear to state that if an identifying TO currently obtains SER/FR data for another entity's BES Elements connected to the same bus, then the identifying TO is responsible for collection of data for all applicable BES Elements on that bus. If the other entity adds equipment directly connected to the same bus after the study is performed, who is responsible for collecting information for the newly added BES Elements?
2. Requirements 5.4 and 13: It's unclear what happens to past identified BES Elements when a future revision occurs. Is the entity required to maintain compliance with the past study results, what does the transition to the new BES Elements look like, how does a transition occur if there is a shared facility and one entity is collecting another entity's SER/FR or DDR data and then decides to transition out of that location?
3. Step 7, the 15% value has only two significant digits, which would allow a 15.4% value to be equal to 15%. If this is not the outcome the STD wishes, we suggest the SDT to increase the significant digits to 15.0%.
4. The technical rationale clearly states on page 5 that directly connected requires the BES Elements to share a common ground grid. Therefore, if BES Elements are on separate ground grids, by default then, they are not directly connected – is this correct?
5. If equipment is added to a bus, e.g., a bay is added to a substation (more breakers) or a bus is extended, is SER and FR data required for these BES Elements if the bus is currently identified as requiring SER/FR information or are these new BES Elements exempt until the subsequent study?
6. If two buses are modeled as a single bus pursuant to the TO's Attachment 1 process through the TO's modeling software, e.g., small generator interconnection bus connecting to existing switchyard, are both buses required to comply with SER/FR requirements if the two buses are on separate ground grids or is the TO required to model the two buses separately?
7. For Figure 5 in the technical rationale, if Breaker 3 was not on a common ground grid with Breakers 1 and 2 then Breaker 3 would be exempt – correct?
8. On page 9 in the Technical Rationale, if the TO does not want to be responsible for the compliance requirement of recording data for the GO's BES Elements, can it still notify the GO of the GO's need to collect SER/FR data? This Standard is unclear as to whether if the TO has the ability to collect data whether it now becomes the entity that must show compliance. We believe that the owner of the equipment is required to show compliance, and how the owner does that can be through agreements as discussed in previous versions of this Standard. Is the STD now taking a different position on this issue?

9. In Figures 9 and 10 of the Technical Rationale, BES Reactors connect through Breakers M and I respectively. Both Breakers M and I are required to have SER and FR data collected, however, it does not appear that Breakers M or I are "directly connected" to the identified buses. Can the STD add additional explanation as to why these two breakers require data collection?

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro appreciates the opportunity to comment.

For consistency and clarity (as outlined in more detail in the rationale below), BC Hydro recommends that that the wording "under its purview" be replaced with "within its Reliability Coordinator Area" within Requirement R5 Part R5.4.

Rationale:

Consistency: "within its Reliability Coordinator Area", or very similar wording, is used in several other standards, including IRO-008, IRO-009, IRO-002, IRO-010, IRO-014, IRO-017, FAC-011, FAC-014, COM-001, EOP-006, EOP-010, EOP-011, when an RC Requirement applicability purview is only RC's own footprint. Using terminology that is different from that used in other standards may be conducive to infer a different meaning.

Clarity: In some cases the RC has a purview that extends beyond its Reliability Coordinator Area (defined in the NERC Glossary of Terms); for example, IRO-008-2 Requirements R1 and R5 reference "its Wide Area" (also a NERC Glossary Term) to describe the RC's obligation.

More specifically to the RC's purview, the NERC Reliability Functional Model version 5.1 (page 30) references "Wide Area" as follows.

"The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits."

"Thus, the Reliability Coordinator needs a "Wide Area" view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits."

If the SDT intended "purview" to mean "within its Reliability Coordinator Area" then this meaning could appear to be in conflict with how it is used in the functional model.

For the reasons outlined above, BC Hydro believes that using "within its Reliability Coordinator Area" instead of "under its purview" within Requirement R5 Part R5.4 will help alleviate possible misinterpretations.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	
Comment	
Minnkota supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	
In regards to R1 and the bus selecting methodology, should there be an exclusion for generator collector buses, as exists in the CIP standards (i.e. CIP-002 2.4)? For example, in figure 8 from the Technical Rationale, if the same entity owns the Transmission and Generation buses, would both buses be counted as BES buses in the selecting methodology (if short circuit MVA falls within the 10 percent highest)? Is a generator collector bus, regardless of ownership, excluded from the R1 applicable BES buses?	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5 - NPCC	

Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5 - RF, Group Name DTE Energy	
Answer	
Document Name	
Comment	
none at this time	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Clarifications provided in this revision are welcome changes. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	

Document Name	
Comment	
SIGE recommends the implementation period be amended to "five (5) calendar years". SIGE believes the three-year implementation period may be too restrictive given set project cycles and several challenges faced by the industry including outage constraints due to capacity shortfalls and long lead-times due to supply chain issues.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE remains concerned that there is a risk that entities may inconsistently apply Attachment 1, which could result in improper placement of disturbance monitoring equipment and therefore inadequate disturbance analysis. Inadequate analysis may lead to risks to reliability not being properly addressed. For example, there may be a need for more buses, based on equal amounts of short circuit capability not being addressed and the interpretation of the steps. Texas RE encourages the SDT to reevaluate including changes to Attachment 1 as part of this project.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI again notes that the Compliance language in Section C does not appear to be the most up-to-date language. The most up-to-date language should be used in the revised Reliability Standard.	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
It is our opinion that the clarifications provided in this revision are welcome changes. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Footnote 2 in the Implementation Plan contains an error that appears to be a carryover from the Project 2015-09 Implementation Plan, which included PRC-002-3. The footnote in the Draft 2 Implementation Plan states: *PRC-002-2 and PRC-002-3, Implementation Plans: "Entities shall be 100 percent compliant with new BES [Bulk Electric System] Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator."* "Transmission Operator" should be "Transmission Owner", as PRC-002-2 nor PRC-002-3 have Transmission Operator applicability. Also, under PRC-002-2, R5 was applicable to Planning Coordinators in the Eastern Interconnection (no Reliability Coordinator applicability in the Eastern Interconnection). We suggest the footnote 2 language be modified to be relevant to the latest regulatory approved version (PRC-002-3), and the "Transmission Operator" language be corrected. Suggested rewording for footnote 2: *PRC-002-3 Implementation Plan: "Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Owner or the Reliability Coordinator, respectively."* NERC should determine if a corrected/errata version of the Project 2015-09 Implementation Plan needs to be submitted to the appropriate governmental approval authority.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	

Document Name	
Comment	

The last page contains a High Level Requirement Overview for each requirement, and R5 was not changed. However, the MRO NSRF requests the STD clean up a discrepancy within this table in the final draft of PRC-002-4. Section 4, Applicability, only includes the RC, TO, and GO. However, this table lists the “RE (PC | RC)” as the applicable entity for R5. Please revise this to RC only.

Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	
Document Name	
Comment	

Recommend: The GO’s and TO’s shall retain evidence for six calendar years or since last audit period, whichever is shorter.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment	
SPP recommend that the drafting team remove the Regional Entity (RE) and Planning Coordinator (PC) from the Requirement R5 section of the High Level Requirement Overview. Currently, this section of the standard does not align with the Functional Entities of the document. In an addition to, Requirement R5 language in the standard is only applicable to the Reliability Coordinator (RC).	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	

Comments received from Ruida Shu/NPCC RSC

1. Do you agree with the revisions to Requirement 1?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with including the implementation plan information in proposed Requirement R13?

   ☐ Yes
   ☐ No

   Comments: We agree but it must respect R8 that says that if the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, we can use the existing equipment with the triggers of the 8.1 and 8.2.

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

   Comments:
   Data Retention: Recommend: The GO's and TO's shall retain evidence for six calendar years or since last audit period, whichever is shorter.

Please considering updating section C. Compliance to use the most up-to-date version of the NERC wording for section C. Compliance. The wording used in Section C. Compliance, for draft 2 of PRC-002-4, is obsolete.

Consideration of Comments

Project Name:	2021-04 Modifications to PRC-002 | Draft 2
Comment Period Start Date:	9/26/2022
Comment Period End Date:	11/10/2022
Associated Ballot(s):	2021-04 Modifications to PRC-002 | Draft 1 Implementation Plan AB 2 OT 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 AB 2 ST

There were 46 sets of responses, including comments from approximately 89 different people from approximately 63 companies representing 8 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, 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, contact Vice President of Engineering and Standards Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Do you agree with the revisions to Requirement 1?

2. Do you agree with including the implementation plan information in proposed Requirement R13?

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					David Hartman	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bob Soloman	Hoosier Energy Electric Cooperative	1	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5	RF	DTE Energy	patricia ireland	DTE Energy	4	RF
					Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6,7	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc	2	MRO
					Brett Springfield	Southwest Power Pool Inc.	2	MRO
Tim Kelley	Tim Kelley		WECC	SMUD / BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the revisions to Requirement 1?	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

The Standard Drafting Team (SDT) should consider combining Parts 1.1 and 1.3 (retiring Part 1.3). The SDT should consider whether "fault" should be capitalized in R1, Part 1.1, since it is a defined term in the NERC Glossary of Terms Used in Reliability Standards and is capitalized in Attachment 1. A possible rewording for Part 1.1:

"1.1. Identify BES buses for which sequence of events recording (SER) and **F**ault recording (FR) data is required by using the methodology in PRC-002-4, Attachment 1. **After the initial performance, re-evaluate all BES buses at least once every five calendar years.**"

If Part 1.3 is retired / combined into Part 1.1, then the proposed edit to Attachment 1, Step 7 should also be modified. It could be revised to "During re-evaluation per Requirement R1, **Part 1.1**, if the three phase short circuit…".

R1, Part 1.2, as proposed in Draft 2 doesn't seem to require the Transmission Owner to inform "other owners of BES Elements directly connected to those BES buses" if a BES Element identified in a prior performance of Part 1.1 is not identified as requiring SER or FR data as part of a re-evaluation. This could potentially result in a misinformed PRC-002 compliance obligation to the other owners of those BES Elements. A possible rewording for Part 1.2:

"1.2. Notify the other owners of BES Elements directly connected to those BES buses, that SER or FR data is required for those BES Elements **(or determined not to be required upon a re-evaluation)**, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1."

For footnote 1 (page 3 of the Draft 2 "clean" version), we recommend that "elements" be capitalized since it is capitalized within R1 (part 1.2) and is a defined term in the NERC Glossary of Terms Used in Reliability Standards.

The SDT should consider adding a footnote that identifies the initial effective date of PRC-002-2, R1 (7/1/2016). For Transmission Owners that have maintained their registration as a TO continuously since before 7/1/2016, this is the date that their initial performance of R1 was required.

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The SDT had discussed combining R1, Part 1.1 and R1, Part 1.3; however, agreed to keep those parts separate. The first draft of this revision included a requirement to notify BES Element owner if no longer required to have SER/FR data. However, based on industry comments that such a requirement is administrative in nature and does not improve reliability, it was removed from the subsequent draft. Footnote 1 is revised as suggested. In general, NERC standards does after going through revisions does not include a footnote identifying an initial effective date of the standard.	
John Daho - MEAG Power - 1 - SERC	
Answer	Yes
Document Name	
Comment	
MEAG Power agrees with revising R1 but further clarification is needed for 1.2 as shown in the technical Rationale. Below is suggested language:- 1.2.1 "Notify the other owners of BES Elements directly connected to those BES buses, that SER or FR data is required for those BES Elements" 1.2.2 "SER or FR data is only required if the Transmission Owner who identified the BES buses in Part 1.1 dos not have SER/or FR data for the BES Elements it doesn't own.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support. The SDT has carefully drafted the requirement R1, Part 1.2. Based on latest round of comments/ballot results, industry has welcomed revision in its current form.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	

Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with the revisions.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation has no comments.	

Kimberly Turco, on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy asks the DT for clarification on R1.3. Per R1.3, would notification be required every five years if the other owner was notified previously. If the other owner was notified previously and the data is currently being monitored, would notification still be required?	
Likes 0	
Dislikes 0	
Response	
The standard is written to require notification following a re-evaluation.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments.	
Likes 0	
Dislikes 0	

Response	
Thanks for your support.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Minnkota supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support. Please see response to comment submitted by MRO NERC Standards Review Forum.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes

Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) appreciates the opportunity to respond and thanks the drafting team for their efforts. While the changes to R1 do not directly impact SIGE's procedures, SIGE would like to highlight the potential that the revisions may be burdensome on industrial customers and municipalities that may not readily have access to SER or FR data at the time of notification.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support. Revisions in this version of the standard are clarifying in nature.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE recommends Footnote 1 be revised to capitalize "elements" as it is a defined term in the NERC Glossary. The Technical Rationale document does capitalize the term.	
Likes 0	
Dislikes 0	
Response	
Thanks for bringing this error to SDT's attention. Revised as suggested.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment	
EEI agrees with the changes made to Requirement 1 and the associated subparts and is sufficient to clarify when SER and FR notifications are made to “other owners” of BES Elements where SER and FR data is required.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF has no comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Provides notification clarification and lessens duplication in FR/SER data collection implementation.	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Mike Magruder - Avista - Avista Corporation - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5 - RF, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	

BC Hydro supports the revisions to Requirement R1 as proposed in Draft 2 of PRC-002-4. BC Hydro however is not supportive of the addition of the wording "under its purview" within Requirement R5 Part 5.4 of proposed PRC-002-4, and recommends that this wording be replaced with "within its Reliability Coordinator Area." BC Hydro acknowledges the SDT's response to industry comments on Draft 1 to clarify that "under its purview" and "within its RC Area" have the same intended meaning and BC Hydro supports this interpretation. However, the wording "within its RC Area" is being consistently used in several other Reliability Standards (e.g. IRO-008, IRO-009, IRO-002, IRO-010, IRO-014, IRO-017, FAC-011, FAC-014, COM-001, EOP-006, EOP-010, EOP-011) and helps differentiate from wording such as "its Wide Area", which has a different meaning. Therefore, BC Hydro believes that using the "within its RC Area" reinforces consistency across Reliability Standards and adds clarity that will alleviate the risk of possible misinterpretations. BC Hydro also recommends that the Technical Rationale document be updated to explain this change to the wording of the Requirement R5.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Revised as suggested.	
Constantin Chitescu - Ontario Power Generation Inc. - 5 - NPCC	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to comment submitted by NPCC Regional Standards Committtee.	

2. Do you agree with including the implementation plan information in proposed Requirement R13?	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The new Requirement R13 simply relocates implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself, and clarifies the implementation time, which was "three years" in the PRC-002-2 implementation plan, to "three calendar years". This change from "three years" to "three calendar years" specifies a more definitive deadline instead of three years from a notification. The notification requirement is specified in R1, Part 1.3 or R5, Part 5.4. The notification may occur after re-evaluation. The re-evaluation is required at least once every five calendar years.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	

Response	
Thanks for your comment. The new Requirement R13 simply relocates implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself, and clarifies the implementation time, which was "three years" in the PRC-002-2 implementation plan, to "three calendar years". This change from "three years" to "three calendar years" specifies a more definitive deadline instead of three years from a notification. The notification requirement is specified in R1, Part 1.3 or R5, Part 5.4. The notification may occur after re-evaluation. The re-evaluation is required at least once every five calendar years.	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments, **and additionally OPG suggests the following modification**: "R13…If the equipment was installed prior to the effective date of this standard **or prior to the 5year re-evaluation/notification of newly identified BES Elements for which DDR is required,** and is not capable of continuous recording, triggered records must meet the following:…" The above proposed wording will allow the entities identified, part of a 5year re-evaluation/notification, as owning BES Elements for which DDR is required, to use the already existing installed equipment albeit installed after the effective date of this standard and prior to the 5year re-evaluation/notification.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. In Requirement R8, "effective date of this standard" is replaced with "effective date of the Reliability Standard PRC-002-2". The drafting team believes that equipment to record DDR data installed after the effective date of Reliability Standard PRC-002-2 needs to meet the continuous recording requirement. The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.	
Constantin Chitescu - Ontario Power Generation Inc. - 5 – NPCC	
Answer	No

Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments, **and additionally OPG Suggests the following modification**: "R13…If the equipment was installed prior to the effective date of this standard **or prior to the 5year re-evaluation/notification of newly identified BES Elements for which DDR is required,** and is not capable of continuous recording, triggered records must meet the following:…" The above proposed wording will allow the entities identified, part of a 5year re-evaluation/notification, as owning BES Elements for which DDR is required, to use the already existing installed equipment albeit installed after the effective date of this standard and prior to the 5year re-evaluation/notification.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. In Requirement R8, "effective date of this standard" is replaced with "effective date of the Reliability Standard PRC-002-2". The drafting team believes that equipment to record DDR data installed after the effective date of Reliability Standard PRC-002-2 needs to meet the continuous recording requirement. The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.	
Mike Magruder - Avista - Avista Corporation - 1 - WECC	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The new Requirement R13 simply relocates implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself, and clarifies the implementation time, which was “three years” in the PRC-002-2 implementation plan, to “three calendar years”. This change from “three years” to “three calendar years” specifies a more definitive deadline instead of three years from a notification. The notification requirement is specified in R1, Part 1.3 or R5, Part 5.4. The notification may occur after re-evaluation. The re-evaluation is required at least once every five calendar years.

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The new Requirement R13 simply relocates implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself, and clarifies the implementation time, which was “three years” in the PRC-002-2 implementation plan, to “three calendar years”. This change from “three years” to “three calendar years” specifies a more definitive deadline instead of three years from a notification. The notification requirement is specified in R1, Part 1.3 or R5, Part 5.4. The notification may occur after re-evaluation. The re-evaluation is required at least once every five calendar years.	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	Yes
Document Name	
Comment	
We agree but it must respect Requirement R8 that says that if the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, we can use the existing equipment with the triggers of the 8.1 and 8.2.	
Likes 0	

Dislikes 0	
Response	
Thanks for your comment. In Requirement R8, “effective date of this standard” is replaced with “effective date of the Reliability Standard PRC-002-2”. The drafting team believes that equipment to record DDR data installed after the effective date of Reliability Standard PRC-002-2 needs to meet the continuous recording requirement. The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions..	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Provides implementation clarification to the ongoing re-evaluation and following R1 part 1.3 notification.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF has no comments.	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

The SDT should consider additional edits to R13, Part 13.1 to clarify applicability. A possible rewording for Part 13.1:

"13.1. Within three (3) calendar years of completing a re-evaluation **under Requirement 1, Part 1.1 (TO)** or receiving notification under Requirement R1, **Part 1.2 (TO or GO)**, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses."

The SDT should also consider possible mis-interpretations of "three (3) calendar years". Based on the *ERO Enterprise CMEP Practice Guide: Implementation of "Annual" and "Calendar Month(s)" in the Reliability Standards* (dated April 19, 2019), a Calendar Year is considered as "beginning on January 1 and ending on December 31". If a notification is received in December, would the second calendar year begin on the adjacent January? The SDT should consider changing this to "within 36 calendar months".

Likes 0	
Dislikes 0	
Response	

Thanks for your comment. The Requirement R13, Part 13.1 as written is clear and proposed details are not necessary.

In regard to mis-interpretation of "three calendar years", the SDT received following explanation from NERC staff: If the notification is received in December (e.g., December 5, 2022), the entity would get three full years (i.e. December 5, 2025), and then under the "calendar year" rule, until December 31, 2025.

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the implementation plan being included in Requirement R13 given this is an ongoing requirement.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
We agree but it must respect R8 that says that if the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, we can use the existing equipment with the triggers of R8.1 and R8.2.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. In Requirement R8, “effective date of this standard” is replaced with “effective date of the Reliability Standard PRC-002-2”. The drafting team believes that equipment to record DDR data installed after the effective date of Reliability Standard PRC-002-2 needs to meet the continuous recording requirement. The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	

SIGE supports moving the timeframe from the implementation plan to Requirement R13; however, SIGE recommends that the implementation period be amended to “five (5) calendar years”. SIGE believes the three-year implementation period may be too restrictive given set project cycles and several challenges faced by the industry including outage constraints due to capacity shortfalls and long lead-times due to supply chain issues.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The scope of SAR only allows the SDT to relocate implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself. The SDT did change the implementation time from “three years” to “three calendar years”. But increasing implementation time to “five calendar years” is not in the scope of this SAR.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	

Minnkota supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support. Please see response to comment submitted by the MRO NERC Standards Review Forum.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP thanks the Standards Drafting Team for their consideration of AEP's previous comments, and in changing from a "three year" period of time to have data in response to notification(s) under R1 to a "three calendar year" period under the proposed R13.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Moving the new SER, FR, or DDR element timetable from the Implementation Plan to the standard requirements is the appropriate location.	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Moving the new SER, FR, or DDR element timetable from the Implementation Plan to the standard requirements is the appropriate location. Kimberly Turco, on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E agrees with locating the Implementation Plan information within Requirement R13 and the clarification it is 3 calendar years.	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5 - RF, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thanks for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thanks for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
John Daho - MEAG Power - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy suggests the time-based requirements in R13.1 and R13.2 be increased from three calendar years to five calendar years. There are multiple challenges to implementing a transmission project within a three-year time period, the most prominent being that it could impact the scheduling and implementation of projects underway pursuant to compliance with other standards (e.g., TPL-001). Additionally, Duke Energy operates on a 3-year budget cycle, and a three calendar year requirement would present scheduling issues at the back end of the budget cycle. A five calendar year requirement would eliminate these scheduling and implementation challenges.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The scope of SAR only allows the SDT to relocate implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself. The SDT did change the implementation time from “three years” to “three calendar years”. But increasing implementation time to “five calendar years” is not in the scope of this SAR.	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	
Document Name	

Comment	
PG&E wishes to thank the Standard Drafting Team (SDT) for their effort and inclusion of our and others' earlier comments in this draft..	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco, on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	

Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no additional comments	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
While AEP agrees in principle with the overall efforts of the Standards Drafting Team, we would like to once again express our concern regarding the associated Technical Rationale document. As we shared in our previous comments, Technical Rationale documents are only to assist in the technical understanding of a requirement and/or Reliability Standard, and should not include compliance examples or compliance language. As previously stated, AEP believes the examples provided in the proposed Technical Rationale document (especially on pages 4 through 15) go beyond mere technical understanding of the obligations and could possibly be referenced in the determination of compliance of those obligations. As such, we believe it would be more appropriate for this content to be embedded within the standard itself, perhaps as an "Attachment 3."	

In future revisions of PRC-002 (i.e. outside of the current project phase), it may be worth considering the following…

1) Generator Owners could benefit from guidance within the standard regarding the thresholds in Step 7 of Attachment 1 and in clearly understanding when those have been met. When these obligations were originally developed, the “top 10 percent” methodology was a sound place to begin, but going forward, more flexibility in this regard would certainly be beneficial.

2) Develop clarity within the standard regarding re-evaluations that result in a site(s) no longer being in scope. Specifically, exactly how much time must pass until those sites may be considered no longer PRC-002 reportable?

Likes 0	
Dislikes 0	

Response

Thanks for your comment. The SDT is bound by NERC rules. It is not a common to practice to include examples provided in the Technical Rationale document as an attachment to a standard. The SDT hopes that examples and related material included in the Technical Rationale would serve the industry well.

The SDT may consider comments that are outside of current project phase in the next phase of this project.

Bret Galbraith - Seminole Electric Cooperative, Inc. - 6

Answer	
Document Name	

Comment

1. Requirement 1.2: The revisions appear to state that if an identifying TO currently obtains SER/FR data for another entity’s BES Elements connected to the same bus, then the identifying TO is responsible for collection of data for all applicable BES Elements on that bus. If the other entity adds equipment directly connected to the same bus after the study is performed, who is responsible for collecting information for the newly added BES Elements?
2. Requirements 5.4 and 13: It’s unclear what happens to past identified BES Elements when a future revision occurs. Is the entity required to maintain compliance with the past study results, what does the transition to the new BES Elements look like, how does a transition occur if there is a shared facility and one entity is collecting another entity’s SER/FR or DDR data and then decides to transition out of that location?

3. Step 7, the 15% value has only two significant digits, which would allow a 15.4% value to be equal to 15%. If this is not the outcome the STD wishes, we suggest the SDT to increase the significant digits to 15.0%.
4. The technical rationale clearly states on page 5 that directly connected requires the BES Elements to share a common ground grid. Therefore, if BES Elements are on separate ground grids, by default then, they are not directly connected – is this correct?
5. If equipment is added to a bus, e.g., a bay is added to a substation (more breakers) or a bus is extended, is SER and FR data required for these BES Elements if the bus is currently identified as requiring SER/FR information or are these new BES Elements exempt until the subsequent study?
6. If two buses are modeled as a single bus pursuant to the TO's Attachment 1 process through the TO's modeling software, e.g., small generator interconnection bus connecting to existing switchyard, are both buses required to comply with SER/FR requirements if the two buses are on separate ground grids or is the TO required to model the two buses separately?
7. For Figure 5 in the technical rationale, if Breaker 3 was not on a common ground grid with Breakers 1 and 2 then Breaker 3 would be exempt – correct?
8. On page 9 in the Technical Rationale, if the TO does not want to be responsible for the compliance requirement of recording data for the GO's BES Elements, can it still notify the GO of the GO's need to collect SER/FR data? This Standard is unclear as to whether if the TO has the ability to collect data whether it now becomes the entity that must show compliance. We believe that the owner of the equipment is required to show compliance, and how the owner does that can be through agreements as discussed in previous versions of this Standard. Is the STD now taking a different position on this issue?
9. In Figures 9 and 10 of the Technical Rationale, BES Reactors connect through Breakers M and I respectively. Both Breakers M and I are required to have SER and FR data collected, however, it does not appear that Breakers M or I are "directly connected" to the identified buses. Can the STD add additional explanation as to why these two breakers require data collection?

Likes 0	
Dislikes 0	

Response

Thanks for your comments. Many of these comments are seeking interpretation of the standard. The SDT cannot provide interpretation of the standard. Please refer to Compliance Guidance or seek clarification through Request For Interpretation (RFI) process.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	

Document Name	
Comment	

BC Hydro appreciates the opportunity to comment.

For consistency and clarity (as outlined in more detail in the rationale below), BC Hydro recommends that that the wording “under its purview” be replaced with “within its Reliability Coordinator Area” within Requirement R5 Part R5.4.

Rationale:

Consistency: “within its Reliability Coordinator Area”, or very similar wording, is used in several other standards, including IRO-008, IRO-009, IRO-002, IRO-010, IRO-014, IRO-017, FAC-011, FAC-014, COM-001, EOP-006, EOP-010, EOP-011, when an RC Requirement applicability purview is only RC’s own footprint. Using terminology that is different from that used in other standards may be conducive to infer a different meaning.

Clarity: In some cases the RC has a purview that extends beyond its Reliability Coordinator Area (defined in the NERC Glossary of Terms); for example, IRO-008-2 Requirements R1 and R5 reference “its Wide Area” (also a NERC Glossary Term) to describe the RC’s obligation.

More specifically to the RC’s purview, the NERC Reliability Functional Model version 5.1 (page 30) references “Wide Area” as follows.

“The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits.”

“Thus, the Reliability Coordinator needs a “Wide Area” view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits.”

If the SDT intended “purview” to mean “within its Reliability Coordinator Area” then this meaning could appear to be in conflict with how it is used in the functional model.

For the reasons outlined above, BC Hydro believes that using “within its Reliability Coordinator Area” instead of “under its purview” within Requirement R5 Part R5.4 will help alleviate possible misinterpretations.

Likes 0	
Dislikes 0	

Response

Thanks for your comment. Revised as suggested.

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	
Document Name	
Comment	
Minnkota supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. Please see response to comment submitted by the MRO NERC Standards Review Forum.	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	
In regards to R1 and the bus selecting methodology, should there be an exclusion for generator collector buses, as exists in the CIP standards (i.e. CIP-002 2.4)? For example, in figure 8 from the Technical Rationale, if the same entity owns the Transmission and Generation buses, would both buses be counted as BES buses in the selecting methodology (if short circuit MVA falls within the 10 percent highest)? Is a generator collector bus, regardless of ownership, excluded from the R1 applicable BES buses?	
Likes 0	
Dislikes 0	
Response	
The lis of BES buses used for methodology included in Attachment 1 are the ones owned by Transmission Owner. Adding an exclusion for generator collector bus owned by Transmission Owner is outside the scope of this SAR.	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	

Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Constantin Chitescu - Ontario Power Generation Inc. - 5 - NPCC	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5 - RF, Group Name DTE Energy	
Answer	
Document Name	
Comment	

none at this time	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Clarifications provided in this revision are welcome changes. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	
Document Name	
Comment	

SIGE recommends the implementation period be amended to "five (5) calendar years". SIGE believes the three-year implementation period may be too restrictive given set project cycles and several challenges faced by the industry including outage constraints due to capacity shortfalls and long lead-times due to supply chain issues.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The scope of SAR only allows the SDT to relocate implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself. The SDT did change the implementation time from "three years" to "three calendar years". But increasing implementation time to "five calendar years" is not in the scope of this SAR.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE remains concerned that there is a risk that entities may inconsistently apply Attachment 1, which could result in improper placement of disturbance monitoring equipment and therefore inadequate disturbance analysis. Inadequate analysis may lead to risks to reliability not being properly addressed. For example, there may be a need for more buses, based on equal amounts of short circuit capability not being addressed and the interpretation of the steps. Texas RE encourages the SDT to reevaluate including changes to Attachment 1 as part of this project.	
Likes 0	
Dislikes 0	
Response	
Thanks for your comment. The concerns raised are outside the scope of this SAR; however, in next phase of this project to address IRPTF SAR, the SDT may review and change the methodology included in the Attachment 1. The stated concerns may be addressed then.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	

Document Name	
Comment	
EEI again notes that the Compliance language in Section C does not appear to be the most up-to-date language. The most up-to-date language should be used in the revised Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This has been updated.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
It is our opinion that the clarifications provided in this revision are welcome changes. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thanks for your support.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

Footnote 2 in the Implementation Plan contains an error that appears to be a carryover from the Project 2015-09 Implementation Plan, which included PRC-002-3. The footnote in the Draft 2 Implementation Plan states:

PRC-002-2 and PRC-002-3, Implementation Plans: "Entities shall be 100 percent compliant with new BES [Bulk Electric System] Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator."

"Transmission Operator" should be "Transmission Owner", as PRC-002-2 nor PRC-002-3 have Transmission Operator applicability. Also, under PRC-002-2, R5 was applicable to Planning Coordinators in the Eastern Interconnection (no Reliability Coordinator applicability in the Eastern Interconnection). We suggest the footnote 2 language be modified to be relevant to the latest regulatory approved version (PRC-002-3), and the "Transmission Operator" language be corrected. Suggested rewording for footnote 2:

PRC-002-3 Implementation Plan: "Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Owner or the Reliability Coordinator, respectively."

NERC should determine if a corrected/errata version of the Project 2015-09 Implementation Plan needs to be submitted to the appropriate governmental approval authority.

Likes 0	
Dislikes 0	
Response	

Thanks for bringing this to SDT's attention. Revised as suggested.

NERC staff has taken a note of an error in the Project 2015-09 Implementation Plan. This could be handled through special process for correcting errata.

Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF

Answer	
Document Name	
Comment	

The last page contains a High Level Requirement Overview for each requirement, and R5 was not changed. However, the MRO NSRF requests the STD clean up a discrepancy within this table in the final draft of PRC-002-4. Section 4, Applicability, only includes the RC, TO, and GO. However, this table lists the “RE (PC | RC)” as the applicable entity for R5. Please revise this to RC only.

Likes 0	
Dislikes 0	

Response
Thanks for bringing this to SDT’s attention. Revised as suggested.
Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment
OPG supports NPCC Regional Standards Committee’s comments.

Likes 0	
Dislikes 0	

Response
Thanks for your support. Please see response to comment submitted by the NPCC Regional Standards Committee.
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	
Document Name	

Comment
Recommend: The GO’s and TO’s shall retain evidence for six calendar years or since last audit period, whichever is shorter.

Likes 0	
Dislikes 0	
Response	
Thanks for your comment. It is not clear if suggested evidence retention applies to R13 only or other requirements applicable to TOs and GOs. The evidence retention period for R13 is aligned with evidence retention period for R1 and R5.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	
SPP recommend that the drafting team remove the Regional Entity (RE) and Planning Coordinator (PC) from the Requirement R5 section of the High Level Requirement Overview. Currently, this section of the standard does not align with the Functional Entities of the document. In an addition to, Requirement R5 language in the standard is only applicable to the Reliability Coordinator (RC).	
Likes 0	
Dislikes 0	
Response	
Thanks for bringing this to SDT’s attention. Revised as suggested.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	

Response
Thanks for your support.

Comments received from Ruida Shu/NPCC RSC

1. Do you agree with the revisions to Requirement 1?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with including the implementation plan information in proposed Requirement R13?

   ☐ Yes
   ☐ No

   Comments: We agree but it must respect R8 that says that if the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, we can use the existing equipment with the triggers of the 8.1 and 8.2.

3. Provide any additional comments for the Standard Drafting Team to consider, if desired.

   Comments: Data Retention: Recommend: The GO's and TO's shall retain evidence for six calendar years or since last audit period, whichever is shorter.

   Please considering updating section C. Compliance to use the most up-to-date version of the NERC wording for section C. Compliance. The wording used in Section C. Compliance, for draft 2 of PRC-002-4, is obsolete.

   Response:

   Thanks for your comment.

   In Requirement R8, "effective date of this standard" is replaced with "effective date of the Reliability Standard PRC-002-2". The drafting team believes that equipment to record DDR data installed after the effective date of Reliability Standard PRC-002-2 needs to meet the continuous recording requirement. The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions. Section C. Compliance has been updated.

   It is not clear if suggested evidence retention applies to R13 only or other requirements applicable to TOs and GOs. The evidence retention period for

R13 is aligned with evidence retention period for R1 and R5.

End of Report

REMINDER

Standards Announcement

Project 2021-04 Modifications to PRC-002

Additional Ballots and Non-binding Polls Open through November 9, 2022

Now Available

Additional ballots for **Project 2021-04 Modifications to PRC-002** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Wednesday, November 9, 2022** for the following standard and implementation plan:

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements
- Implementation Plan

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Balloting
Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

Note: If a member cast a vote in the previous ballot, that vote will not carry over to this additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in this ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-04 Modifications to PRC-002 Observer List” in the Description Box.

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 2021-04 Modifications to PRC-002

Formal Comment Period Open through November 9, 2022

Now Available

A 45-day formal comment period for **Project 2021-04 Modifications to PRC-002**, is open through **8 p.m. Eastern, Wednesday, November 9, 2022** for the following standard and implementation plan:

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements
- Implementation Plan

The standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. An unofficial Word version of the comment form is posted on the project page.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 31 – November 9, 2022**.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2021-04 Modifications to PRC-002 Observer List" in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/259)
Ballot Name: 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 AB 2 ST
Voting Start Date: 10/31/2022 12:01:00 AM
Voting End Date: 11/10/2022 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 219
Total Ballot Pool: 290
Quorum: 75.52
Quorum Established Date: 11/10/2022 4:19:53 PM
Weighted Segment Value: 96.36

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	81	1	57	0.95	3	0.05	0	3	18
Segment: 2	7	0.5	5	0.5	0	0	0	0	2
Segment: 3	67	1	49	0.961	2	0.039	0	2	14
Segment: 4	15	1	10	1	0	0	0	0	5
Segment: 5	68	1	43	0.935	3	0.065	0	3	19
Segment: 6	46	1	31	0.939	2	0.061	0	2	11
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.4	4	0.4	0	0	0	0	2
Totals:	290	5.9	199	5.685	10	0.215	0	10	71

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Sheraz Majid		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Western Area Power Administration	Sean Erickson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Andrew Gallo		Affirmative	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		None	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya Vannorman	Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		None	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Alice Wright		None	N/A
4	Austin Energy	Tony Hua		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya Vannorman	Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Acciona Energy North America	Krys Rootham		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Buckeye Power, Inc.	Ryan Strom		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		None	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NextEra Energy	Summer Esquerre		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	John Cook	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		None	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Bonneville Power Administration	Tanner Brier		None	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Anirudh Bhimireddy		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Northern California Power Agency	Dennis Sismaet	James Mearns	None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Abstain	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/259)
Ballot Name: 2021-04 Modifications to PRC-002 | Draft 1 Implementation Plan AB 2 OT
Voting Start Date: 10/31/2022 12:01:00 AM
Voting End Date: 11/10/2022 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 218
Total Ballot Pool: 287
Quorum: 75.96
Quorum Established Date: 11/10/2022 3:41:01 PM
Weighted Segment Value: 95.85

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	81	1	57	0.95	3	0.05	0	3	18
Segment: 2	7	0.4	4	0.4	0	0	0	1	2
Segment: 3	67	1	49	0.961	2	0.039	0	2	14
Segment: 4	13	1	10	1	0	0	0	0	3
Segment: 5	67	1	41	0.911	4	0.089	0	3	19
Segment: 6	46	1	30	0.938	2	0.063	0	3	11
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	6	0.4	4	0.4	0	0	0	0	2
Totals:	287	5.8	195	5.559	11	0.241	0	12	69

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Sheraz Majid		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Eric Shaw	None	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Western Area Power Administration	Sean Erickson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Andrew Gallo		Abstain	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		None	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya Vannorman	Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		None	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A
3	Muscatine Power and Water	Seth Shoemaker		None	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya Vannorman	Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Buckeye Power, Inc.	Ryan Strom		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		None	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	North Carolina Electric Membership Corporation	John Cook	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		None	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		None	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Anirudh Bhimireddy		Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		None	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		None	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Abstain	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Showing 1 to 287 of 287 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/259)
Ballot Name: 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 | Non-binding Poll AB 2 NB
Voting Start Date: 10/31/2022 12:01:00 AM
Voting End Date: 11/14/2022 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 218
Total Ballot Pool: 278
Quorum: 78.42
Quorum Established Date: 11/14/2022 10:42:30 AM
Weighted Segment Value: 96.09

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	47	0.959	2	0.041	13	15
Segment: 2	6	0.2	2	0.2	0	0	2	2
Segment: 3	64	1	44	0.957	2	0.043	8	10
Segment: 4	14	1	10	1	0	0	0	4
Segment: 5	68	1	41	0.953	2	0.047	7	18
Segment: 6	43	1	25	0.962	1	0.038	8	9
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	6	0.3	3	0.3	0	0	1	2
Totals:	278	5.5	172	5.331	7	0.169	39	60

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Allen Klassen	Alan Kloster	Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Sheraz Majid		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Abstain	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wegner		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Western Area Power Administration	Sean Erickson		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Andrew Gallo		Abstain	N/A
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Carl Turner	LaKenya Vannorman	Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		None	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Abstain	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Adam Menendez		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Austin Energy	Tony Hua		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya Vannorman	Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Northern California Power Agency	Marty Hostler	James Mearns	None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Buckeye Power, Inc.	Ryan Strom		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Jason Fortik		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	John Cook	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Amy Jones		Affirmative	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Anirudh Bhimireddy		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		None	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Abstain	N/A
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Glen Pruitt		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Abstain	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal comment period with ballot	06/09/2022 – 07/15/2022
45-day formal or informal comment period with additional ballot	09/26/2022 – 11/09/2022
10-day final ballot	12/07/2022 – 12/16/2022
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
5. **Effective Date:** 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-002-4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[1] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-4, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected 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]*

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[1] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

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 directly 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 100 kV 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 Reliability Coordinator 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 Reliability Coordinator'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.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area 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.

M5. The Reliability Coordinator 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 Reliability Coordinator 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 the Reliability Standard PRC-002-2[2] and is not capable of continuous recording, triggered records

[2] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

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 Reliability Coordinator, 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 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

1.2. As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards. **Data 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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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 Enforcement Program:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None.

Violation Severity Levels

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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar	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 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 owners that their BES Elements require SER or FR data by greater than	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	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 number of specified 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 electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified 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 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 Elements and the number of specified electrical	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 electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	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 Reliability Coordinator 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 Reliability Coordinator 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.	The Reliability Coordinator 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 Reliability Coordinator 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	The Reliability Coordinator 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 Reliability Coordinator 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	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator 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 Requirement R7, Parts 7.1 through 7.4 that covers	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.

			more than 80 percent, but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	70 percent, but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	60 percent, but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
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	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner failed to have time synchronization per

			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.	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.	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.	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 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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

			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, 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, 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, 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 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.

R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-4: Implementation Plan.

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.

NERC Reliability Standard PRC-002-4: Technical Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	TBD	TBD	Revised under Project 2021-04

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.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

<u>If the list has more than 11 BES buses:</u> 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>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>

<table>
<tr><th>Requirement</th><th>Entity</th><th>Implementation</th></tr>
<tr><td>R13</td><td>TO | GO</td><td>X</td></tr>
</table>

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal comment period with ballot	06/09/2022 – 07/15/2022
XX-day formal or informal comment period with additional ballot	09/26~~09~~/2022 – 11~~0~~/09~~17~~/2022
XX-day final ballot	12/07~~9~~/2022 – 12~~01~~/16/2022~~3~~
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
5. **Effective Date:** 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-002-4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[1] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-4, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected 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]*

[1] For the purposes of this standard, "directly connected" BES ~~e~~Elements are BES ~~e~~Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

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 directly 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 100 kV 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 Reliability Coordinator 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 Reliability Coordinator’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.

5.4. Re-evaluate all BES Elements within~~under~~ its Reliability Coordinator Area~~purview~~ 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.

M5. The Reliability Coordinator 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 Reliability Coordinator 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 the Reliability Standard PRC-002-2[2] ~~this standard~~ and is not capable of continuous recording,

[2] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

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
○ 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 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 Reliability Coordinator, 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 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards. ~~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~~ Data 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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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 Enforcement Program:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None.

Violation Severity Levels

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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar	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 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 owners that their BES Elements require SER or FR data by greater than	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	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 number of specified 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 electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified 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 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 Elements and the number of specified electrical	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 electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	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 Reliability Coordinator 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 Reliability Coordinator 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.	The Reliability Coordinator 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 Reliability Coordinator 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	The Reliability Coordinator 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 Reliability Coordinator 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	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator 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 Requirement R7, Parts 7.1 through 7.4 that covers	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.

			more than 80 percent, but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	70 percent, but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	60 percent, but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
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	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner failed to have time synchronization per

			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.	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.	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.	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 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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

			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, 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, 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, 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 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.

R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-4: Implementation Plan.

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.

NERC Reliability Standard PRC-002-4: Technical Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	TBD	TBD	Revised under Project 2021-04

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.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

<u>If the list has more than 11 BES buses:</u> 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

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	R~~E~~ ~~(PC | R~~C~~)~~	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

Requirement	Entity	Implementation
R13	TO | GO	X

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	01/20/2021
SAR posted for comment	06/14/2021 – 07/13/2021

Anticipated Actions	Date
45-day formal or informal comment period with ballot	06/09/2022 – 07/15/2022
45-day formal or informal comment period with additional ballot	09/26/2022 – 11/09/2022
10-day final ballot	12/07/2022 – 12/16/2022
Board adoption	02/09/2023 – 03/15/2023

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

N/A.

A. Introduction

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

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

   4.1.2. Transmission Owner

   4.1.3. Generator Owner

5. **Effective Date:** 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-~~3~~4, Attachment 1.

1.2. Notify other owners of BES Elements directly connected[1] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER and FR data. ~~,~~ ~~if any,~~ This notification is required 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 for Requirement R1, Part 1.1 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-~~3~~4, Attachment 1;~~,~~ has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement

[1] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

R1, Part 1.3. ~~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 directly 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 directly 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 Reliability Coordinator 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 Reliability Coordinator'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 within its Reliability Coordinator Area 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 Reliability Coordinator 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 Reliability Coordinator 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 the Reliability Standard PRC-002-2[2] ~~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
○ 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 at least 960 samples per second.

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

[2] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

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 Reliability Coordinator, 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards. ~~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~~ Data 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, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 for five calendar years.~~

The Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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~~ Enforcement Program:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaints

1.4. Additional Compliance Information

None

Violation Severity Levels

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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10- calendar days, but less than or equal to 20- calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20- calendar days, but less than or equal to 30 -calendar days.	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 that their BES Elements require SER or FR data by 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 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 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 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 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 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 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 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator 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	The Transmission Owner had DDR data as directed by	The Transmission Owner had DDR data as directed by	The Transmission Owner failed to have DDR data as

			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.	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.	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.	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 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	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	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	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the

			properties as specified in Requirement R9.	recording properties as specified in Requirement R9.	total recording properties as specified in Requirement R9.	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 11.2~~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	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2~~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	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2~~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	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2~~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.

			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.	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.	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.	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 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.

R13.	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-4: Implementation Plan.~~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.

NERC Reliability Standard PRC-002-4: Technical Rationale.

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.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	**TBD**	**TBD**	Revised under Project 2021-04

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.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. 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

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	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

Requirement	Entity	Implementation
R13	TO | GO	X

Implementation Plan

Project 2021-04 Modifications to PRC-002
Reliability Standard PRC-002-4

Applicable Standard(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Requested Retirement(s)

- PRC-002-3 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner
- Generator Owner

General Considerations

This implementation plan provides that Reliability Standard PRC-002-4 will become effective on the later of: (1) the first day of the first calendar quarter following regulatory approval; or (2) the effective date of PRC-002-3.[1] Additional time to implement this version of Reliability Standard PRC-002-4 is not provided because:

- the revisions to Requirements R1, R3, and R5 are clarifying in nature, and
- the new Requirement R13 simply relocates implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself, and clarifies the implementation time, which was "three years" in the PRC-002-2 implementation plan, to "three calendar years."[2]

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard or as otherwise provided for by the applicable governmental authority; **or** (2) the effective date of PRC-002-3.

[1] In the latter case, Reliability Standard PRC-002-4 will supersede PRC-002-3 prior to it ever becoming effective.
[2] PRC-002-2 and PRC-002-3, Implementation Plans: "Entities shall be 100 percent compliant with new BES [Bulk Electric System] Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator."

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction; **or** (2) the effective date of PRC-002-3.

Retirement Date

The version of Reliability Standard PRC-002 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-002-4.

Prior Implementation Plan

The following element of the Implementation Plan for PRC-002-3 is incorporated herein and modified in case PRC-002-3 is superseded by PRC-002-4:

Reliability Coordinators in the Eastern Interconnection shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3 or six (6) months of the effective date of PRC-002-4, whichever occurs first.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan ~~(Draft)~~

Project 2021-04 Modifications to PRC-002
Reliability Standard PRC-002-4

Applicable Standard(s)

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Requested Retirement(s)

- PRC-002-3 – Disturbance Monitoring and Reporting Requirements

Applicable Entities

- Reliability Coordinator
- Transmission Owner
- Generator Owner

General Considerations

This implementation plan provides that Reliability Standard PRC-002-4 will become effective on the later of: (1) the first day of the first calendar quarter following regulatory approval; or (2) the effective date of PRC-002-3.[1] Additional time to implement this version of Reliability Standard PRC-002-4 is not provided because:

- the revisions to Requirements R1, R3, and R5 are clarifying in nature, and
- the new Requirement R13 simply relocates implementation time prescribed in the PRC-002-2 Implementation Plan to the standard itself, and clarifies the implementation time, which was "three years" in the PRC-002-2 implementation plan, to "three calendar years."[2]

Effective Date

Where approval by an applicable governmental authority is required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard or as otherwise provided for by the applicable governmental authority; **or** (2) the effective date of PRC-002-3.

[1] In the latter case, Reliability Standard PRC-002-4 will supersede PRC-002-3 prior to it ever becoming effective.
[2] PRC-002-2 and PRC-002-3, Implementation Plans: "Entities shall be 100 percent compliant with new BES [Bulk Electric System] Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator."

Where approval by an applicable governmental authority is not required, Reliability Standard PRC-002-4 shall become effective **on the later of:** (1) the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction; **or** (2) the effective date of PRC-002-3.

Retirement Date

The version of Reliability Standard PRC-002 then in effect shall be retired immediately prior to the effective date of the proposed Reliability Standard PRC-002-4.

Prior Implementation Plan

The following element of the Implementation Plan for PRC-002-3 is incorporated herein and modified in case PRC-002-3 is superseded by PRC-002-4:

Reliability Coordinators in the Eastern Interconnection shall be fully compliant with Requirement R5 within six (6) months of the effective date of PRC-002-3 or six (6) months of the effective date of PRC-002-4, whichever occurs first.

Violation Risk Factor and Violation Severity Level Justifications

Project 2021-04 Modifications to PRC-002-3

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. Each requirement is assigned a VRF and a VSL. 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 in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

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.

FERC Guidelines for Violation Risk Factors

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

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect 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
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs 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 VRF 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.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

PRC-002-4

VRF Justification for PRC-002-4, Requirement R1

The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
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 that their BES Elements require SER or FR data 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 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 owners that their BES Elements require SER or FR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	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 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 owners that their BES Elements require SER or FR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

VSL Justifications for PRC-002-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by 10 calendar days or less).
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do 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 VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-4, Requirement R2
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R2
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R3
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R3
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R4
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R4
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R5
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSLs for PRC-002-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	OR The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days but less than or equal to 20 calendar days.	OR The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator failed to ensure a minimum DDR coverage per Part 5.2.

VSL Justifications for PRC-002-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs do not have the unintended consequence of lowering the level of compliance. The SDT clarified the currently approved VSLs by adding language regarding the late notification (e.g. The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less).
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-4, Requirement R5	
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 VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

VRF Justification for PRC-002-4, Requirement R6
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R6
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R7
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R7
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R8
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R8
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R9
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R9
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R10
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R10
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R11
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R11
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justification for PRC-002-4, Requirement R12
The VRF did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VSL Justification for PRC-002-4, Requirement R12
The VSL did not change from the previously FERC approved PRC-002-3 Reliability Standard.

VRF Justifications for PRC-002-4, Requirement R13	
Proposed VRF	**Lower**
NERC VRF Discussion	A VRF of Lower is appropriate due to this Requirement 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. Therefore, it is consistent with the definition of a Lower VRF.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	This VRF is consistent with the identified areas from the FERC list of critical areas in the Final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The VRF for Requirement R13 is consistent with those of other requirements to have DDR, SER, or FR data in the proposed Reliability Standard.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	This VRF is consistent with other VRFs that address similar reliability goals in different Reliability Standards.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	This VRF is consistent with the definition of a lower VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for PRC-002-4, Requirement R13			
Lower	**Moderate**	**High**	**Severe**
	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

VSL Justifications for PRC-002-4, Requirement R13	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for PRC-002-4, Requirement R13	
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	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, 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	Each VSL is based on a single violation and not cumulative violations.

Technical Rationale for Reliability Standard PRC-002-4

April 2022

PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator 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 Requirement 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 Disturbance Monitoring Standard Drafting Team'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-002-4, 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.

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.
5. 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 the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.
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.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B and C are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1600 MVA, 1500 MVA and 1550 MVA respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1550 MVA, 1675 MVA and 1600 MVA respectively. The bus B is the one with highest maximum three phase short circuit MVA now. The three phase short circuit MVA of bus B is within 15% of the three phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1500 MVA, 1750 MVA and 1650 MVA respectively. The three phase short circuit MVA of bus B is greater than 15% of three phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

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 requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of “directly connected” BES Elements are notified. For the purposes of this standard, “directly connected” BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 1 and 2 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

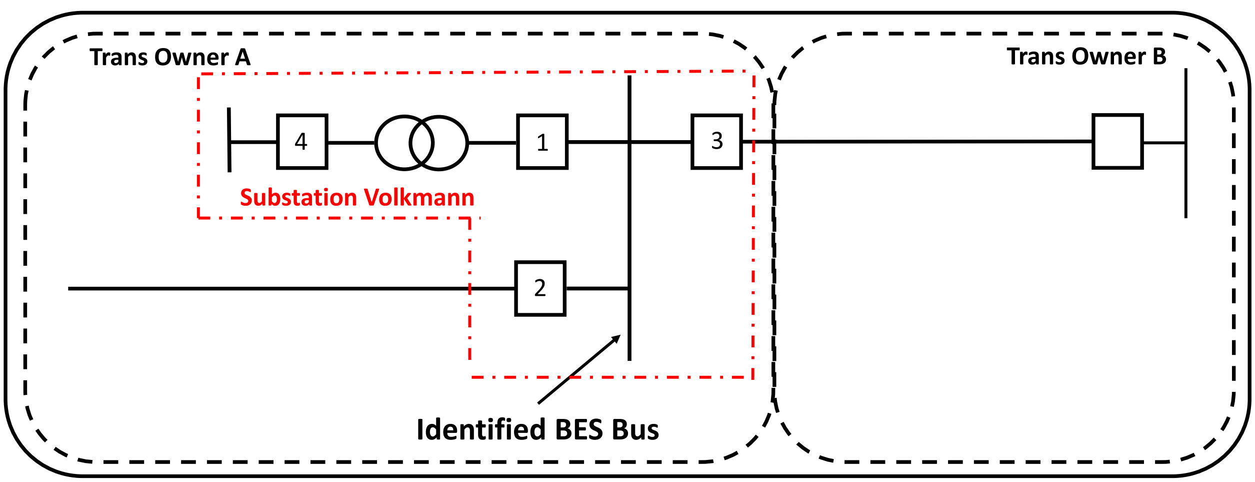

Figure 1: Straight Bus Configuration – Single Owner

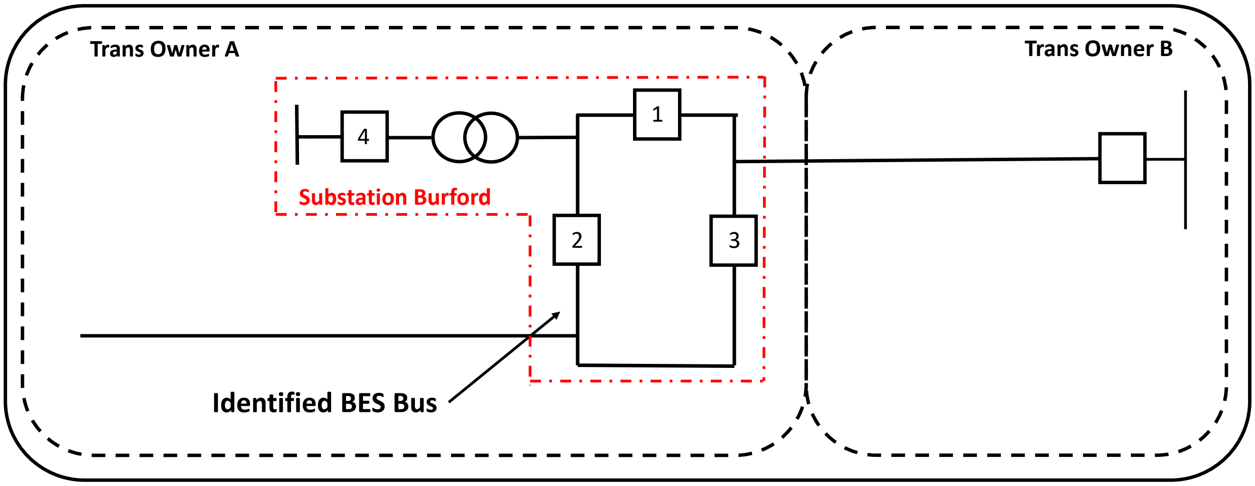

Figure 2: Ring Bus Configuration – Single Owner

Figures 3 and 4 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

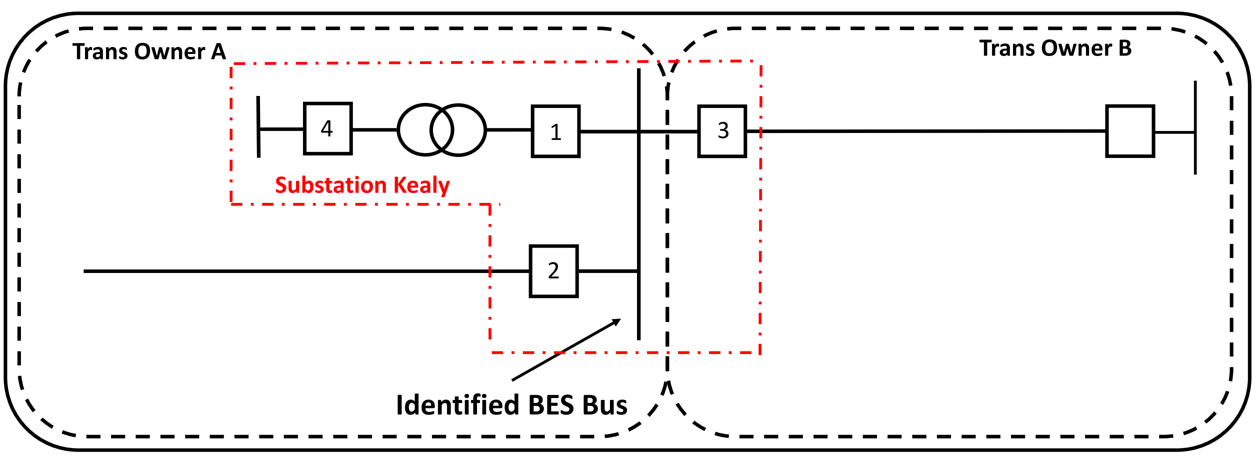

Figure 3: Straight Bus Configuration – Multiple Owners

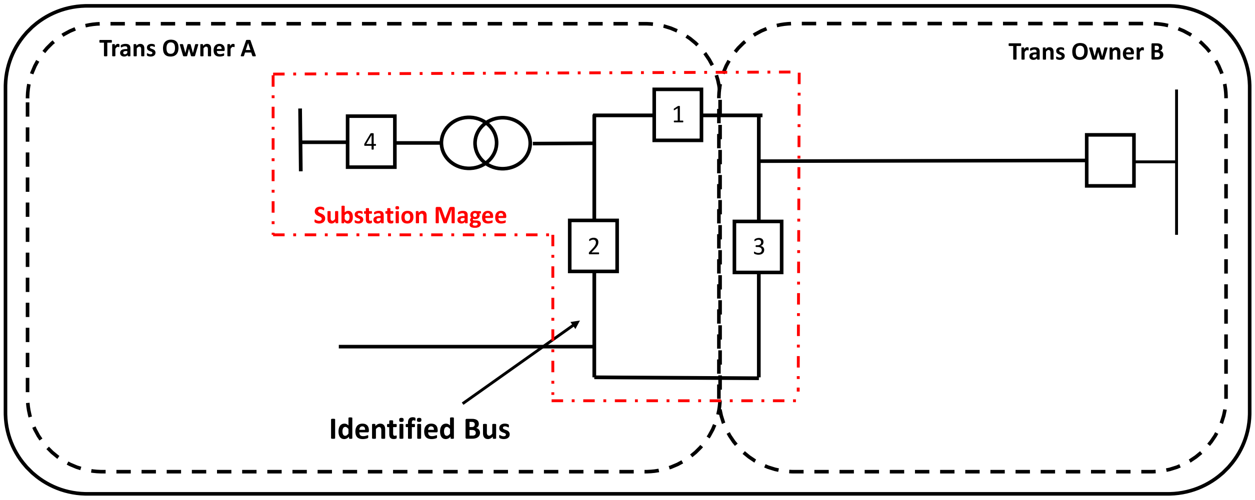

Figure 4: Ring Bus Configuration – Multiple Owners

For examples in Figures 3 and 4, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 5 shows an example with a generator interconnection. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

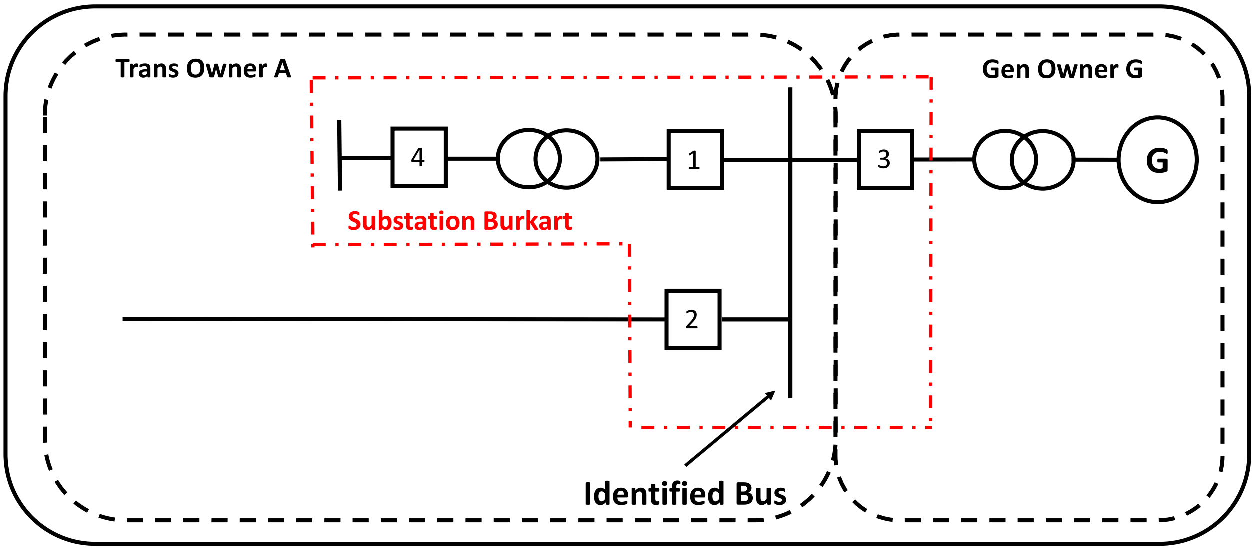

Figure 5: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 6, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

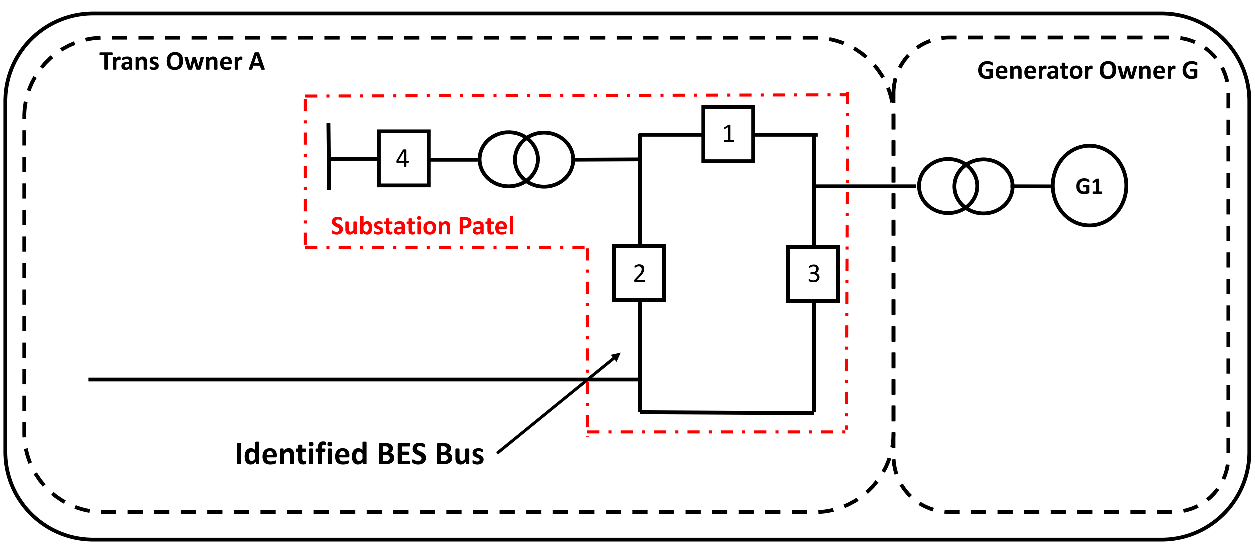

Figure 6: Generator Interconnection to Ring Bus

Figure 7 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical

bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

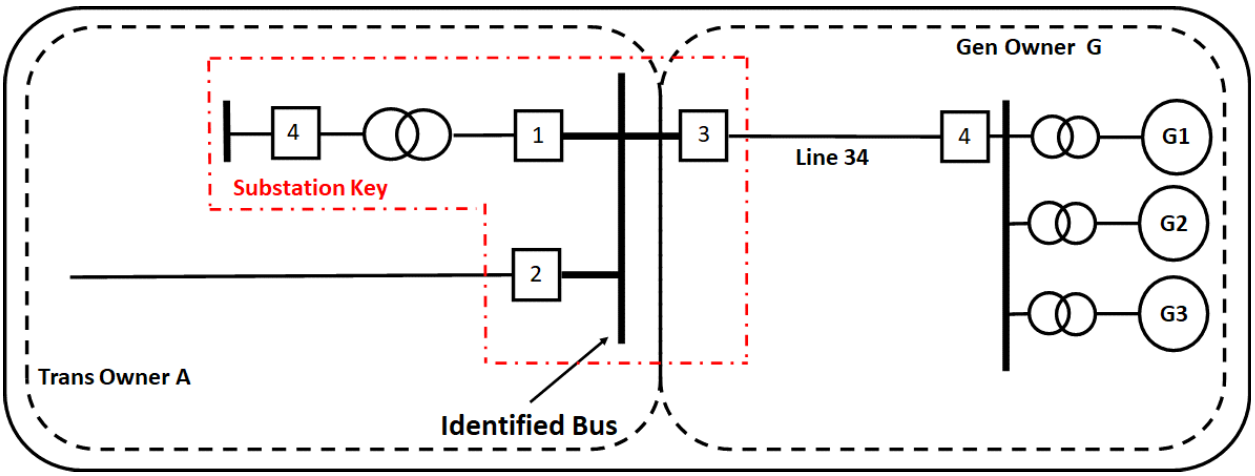

Figure 7: Generator Interconnection via Line 34

Figure 8 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3 and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

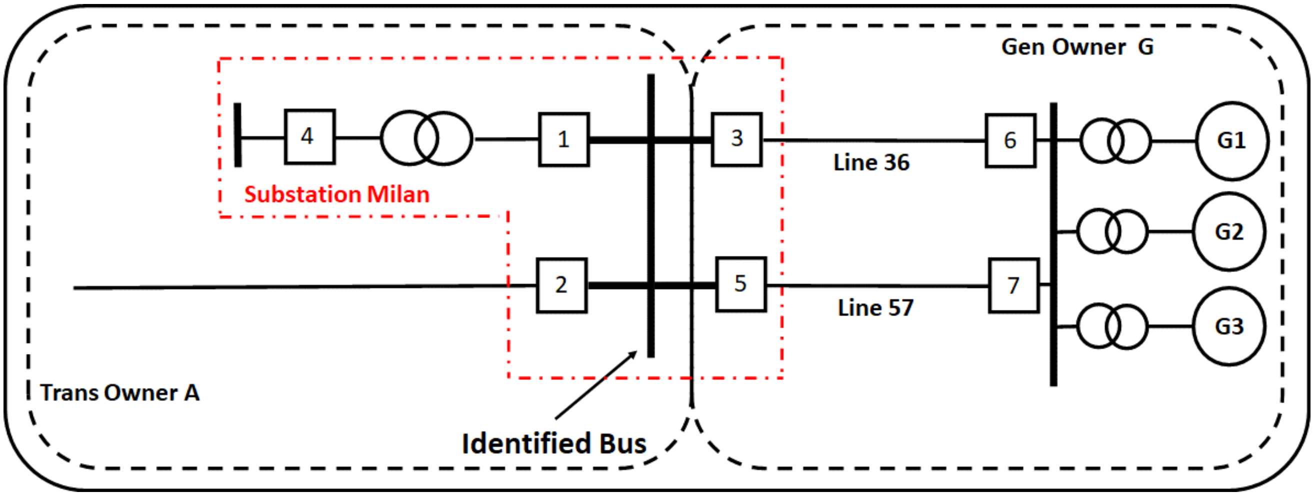

Figure 8: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification_TransmissionOwnerB

Greetings,

In accordance with NERC Standard PRC-002-4, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

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.

Rationale for Requirement 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 directly connected to a BES bus. Change of state of circuit breaker position and 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.

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.

Examples in Figures 9, 10 and 11 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement 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.

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 directly 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 directly 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.

Examples in Figures 9, 10, and 11 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

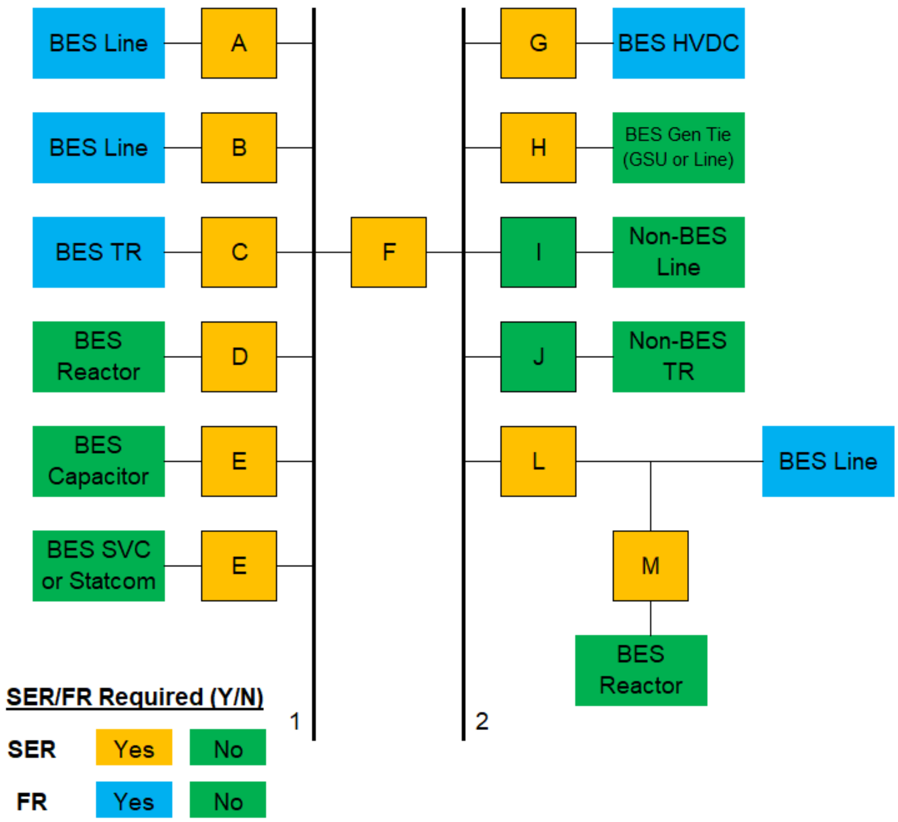

Figure 9: Straight BES Buses

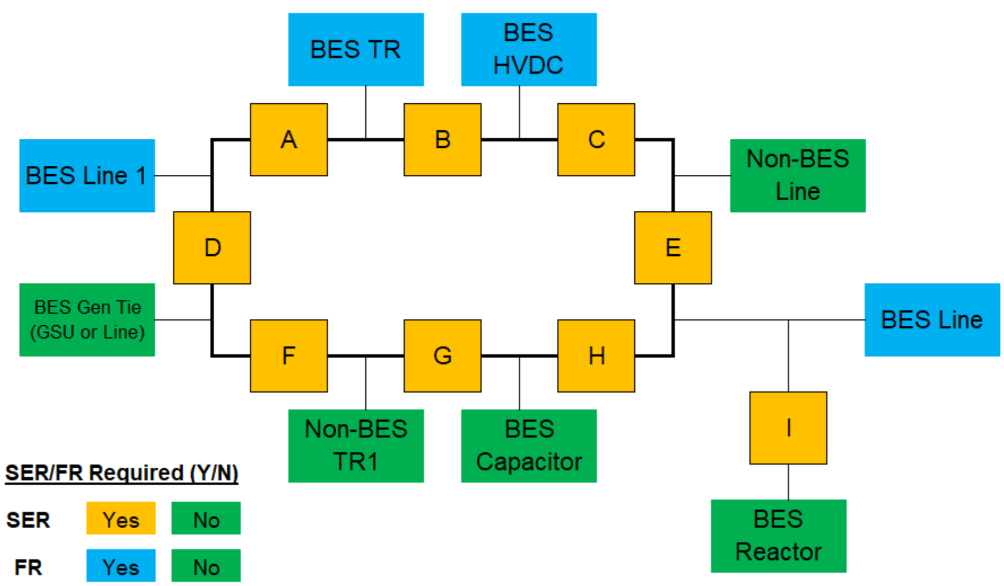

Figure 10: Ring BES Bus

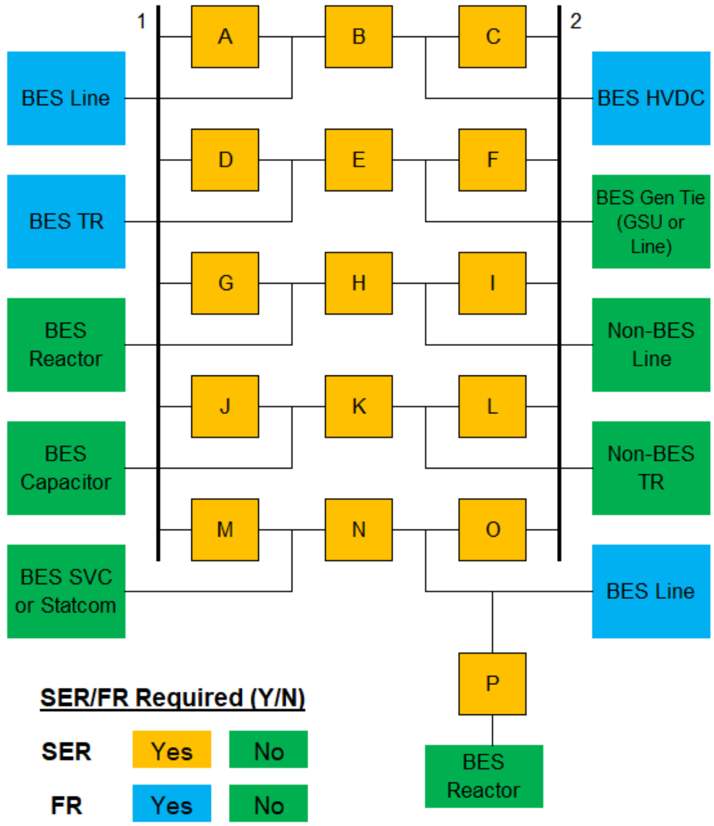

Figure 11: Breaker and Half BES Bus

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

Rationale for Requirement 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.

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.

Rationale for Requirement 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 Reliability Coordinator 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 Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator 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 Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator 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 Reliability Coordinators, each Reliability Coordinator 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 Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator 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 Reliability Coordinators. It is intended that each Reliability Coordinator 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.

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 Reliability Coordinator 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 Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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.).

Rationale for Requirement 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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

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 Reliability Coordinator 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-002-4 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.

Rationale for Requirement 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 eitherthe 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.

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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement 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).

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.

Rationale for Requirement 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.

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.

Rationale for Requirement 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.

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 one millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement 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 11.2, 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. A10-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.

This requirement directs the applicable entities, upon requests from the Reliability 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 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 11.2 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 11.1 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 synchrophasor 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.

Rationale for Requirement 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.

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.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Technical Rationale for Reliability Standard PRC-002-4

April 2022

PRC-002-4 – Disturbance Monitoring and Reporting Requirements

Rationale for Applicability Section

Because the Reliability Coordinator has the best wide-area view of the BES, the Reliability Coordinator 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 Requirement 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 Disturbance Monitoring Standard Drafting Team'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-002-4, 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.

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.
5. 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 the greater of 1500 MVA or 20 percent of the median MVA level determined in Step 5.
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.

Per the methodology in Attachment 1, FR/SER data is required at the BES bus with highest maximum available three phase short circuit MVA when the list in Step 6 has one or more, but less than or equal to 11, BES buses. Requirement R1, Part 1.3 requires re-evaluation of BES buses at least once every five calendar years in accordance with Part 1.1. Depending on results of this re-evaluation, the location at which SER/FR data is required could change due to a minor change in the three phase short circuit MVA. This is especially true for small Transmission Owners which are only required to have SER/FR data for one (1) BES bus per allowance based on the methodology in Attachment 1. To help avoid cost and compliance burden, a criterion that constitutes a change in fault current levels, which would require changing SER and FR data recording locations, is included in Attachment 1. During the re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data, then it is not necessary to change the applicable BES bus.

As an example, during an initial evaluation, three BES buses A, B and C are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1600 MVA, 1500 MVA and 1550 MVA respectively. The SER/FR data is required at Bus A. During a first re-evaluation, the same three buses are identified in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1550 MVA, 1675 MVA and 1600 MVA respectively. The bus B is the one with highest maximum three phase short circuit MVA now. The three phase short circuit MVA of bus B is within 15% of the three phase short circuit MVA of bus A (1675 is only 8% above 1550) where SER/FR data is being recorded. Hence, it is not necessary to change SER/FR data recording location to bus B. During a next re-evaluation, the same three buses are identified again in Step 6. The maximum three phase short circuit MVA of buses A, B and C is 1500 MVA, 1750 MVA and 1650 MVA respectively. The three phase short circuit MVA of bus B is greater than 15% of three phase short circuit MVA of bus A (1750 is 16.7% above the 1500) where SER/FR data is being recorded. Hence, it is necessary to change SER/FR data recording location to bus B.

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 requires DDR data. Refer to Rationale for Requirement R5 for more details.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in Requirement R1, Part 1.2 is necessary to ensure all owners of "directly connected" BES Elements are notified. For the purposes of this standard, "directly connected" BES elements are BES elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100kV are excluded. The following examples are provided to clarify notification requirement.

The straight and ring bus configurations shown in Figures 1 and 2 respectively, are the simplest BES bus configurations. Transmission Owner A owns the identified BES bus, including physical bus(es) as well as all three circuit breakers. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A records SER/FR data for all three circuit breakers. In these cases, Transmission Owner A is not required to send notification to Transmission Owner B.

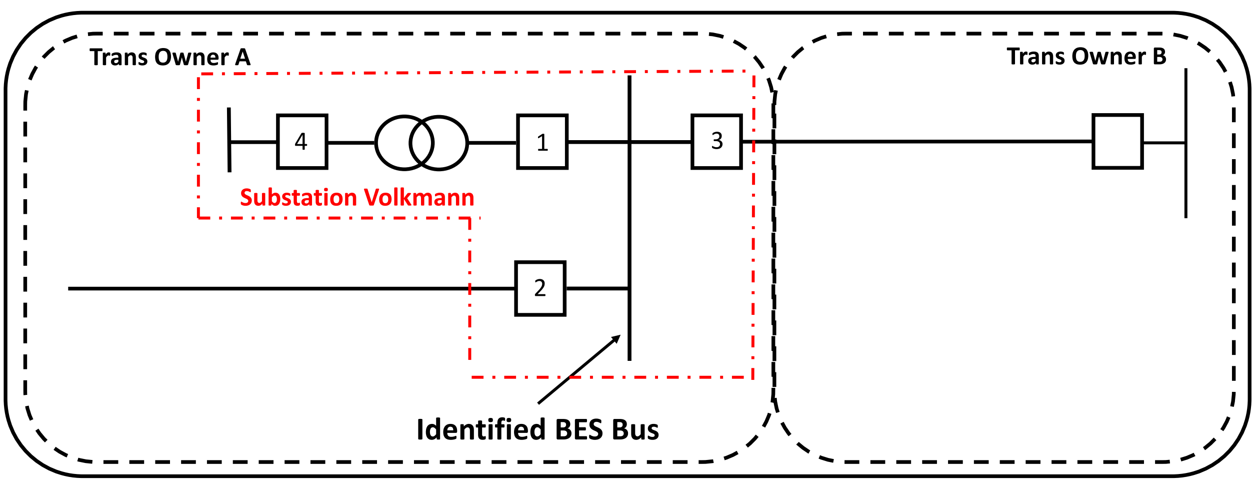

Figure 1: Straight Bus Configuration – Single Owner

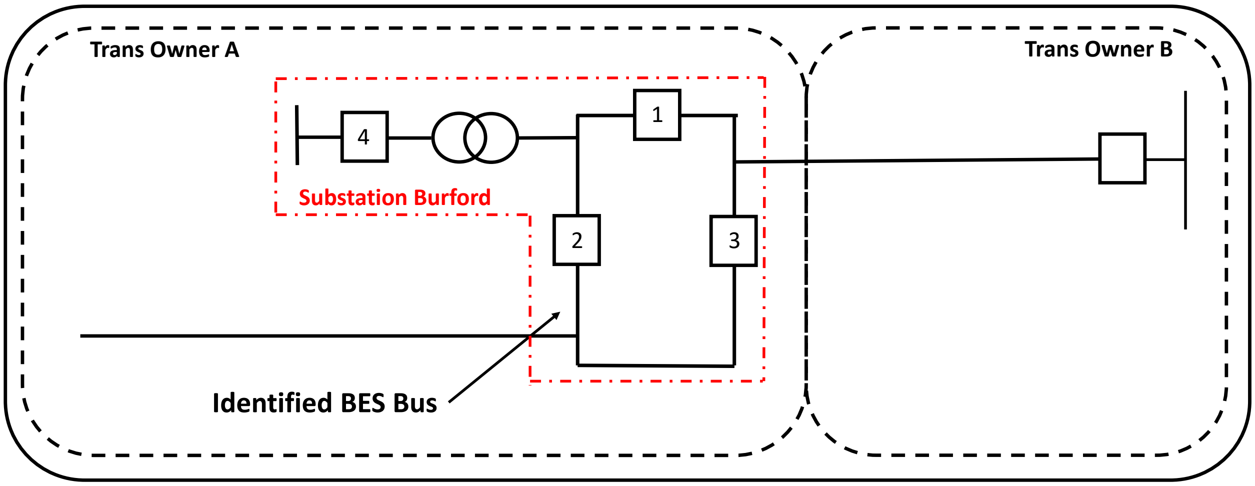

Figure 2: Ring Bus Configuration – Single Owner

Figures 3 and 4 show straight and ring bus configurations respectively, but with equipment that comprise a BES bus owned by multiple owners. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. The Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1 and methodology included in Attachment 1. Transmission Owner A owns a portion of the physical bus(es) as well as circuit breakers 1 and 2. Transmission Owner B owns the remaining portion of the physical bus(es) and directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise the BES bus is located within the same physical space, i.e., substation Kealy, regardless of ownership.

In these cases, Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Transmission Owner B is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER and FR data for circuit breaker 3, then Transmission Owner B must be notified that SER/FR data is required for circuit breaker 3.

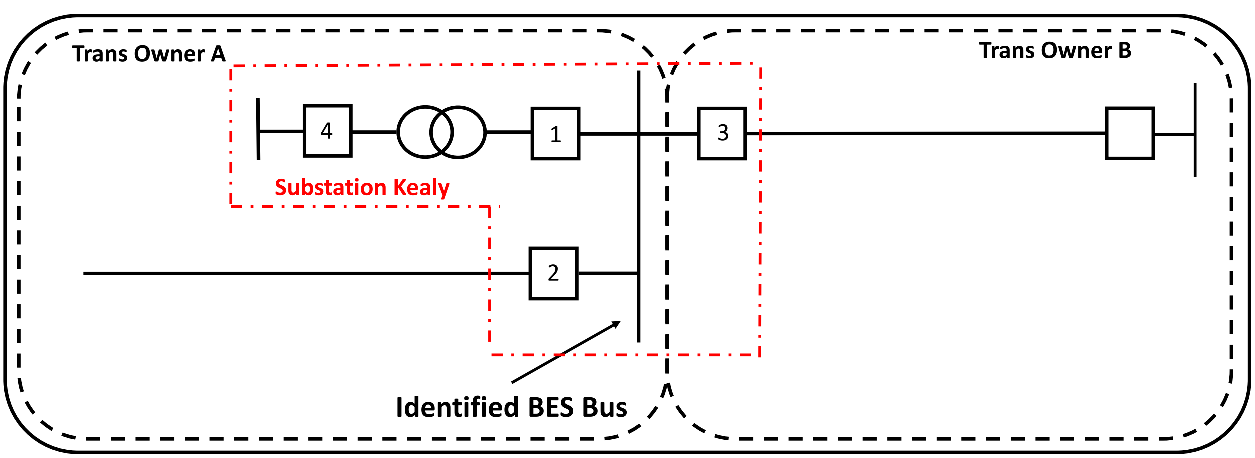

Figure 3: Straight Bus Configuration – Multiple Owners

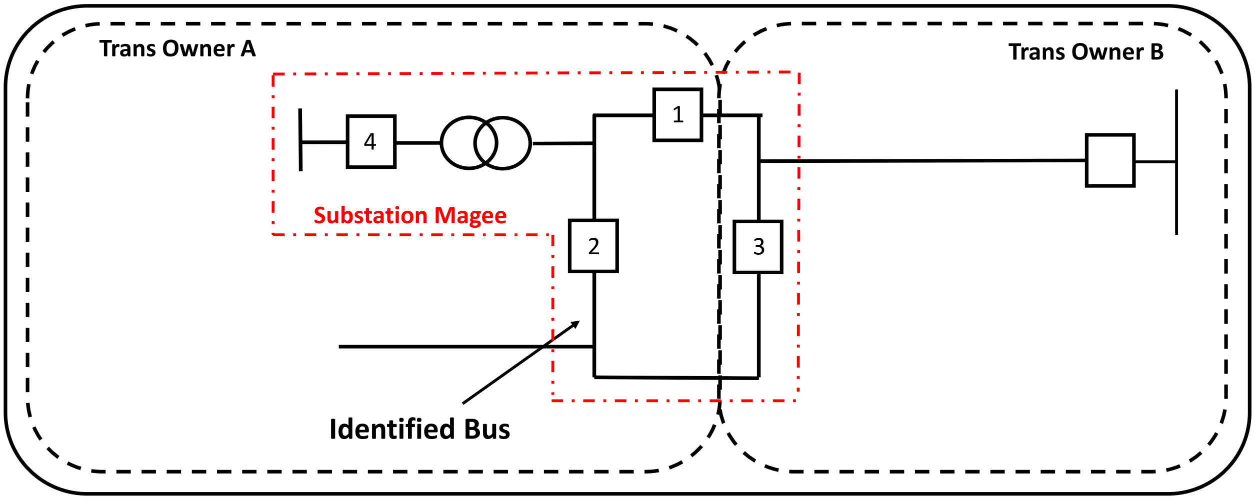

Figure 4: Ring Bus Configuration – Multiple Owners

For examples in Figures 3 and 4, if Transmission Owner A records SER/FR data for circuit breaker 3 (even though owned by Transmission Owner B), then Transmission Owner A is not required to notify Transmission Owner B.

Figure 5 shows an example with a generator interconnection. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A identifies a BES bus for which SER and FR data is required per Requirement R1, Part 1.1. Transmission Owner A owns the physical bus as well as directly connected circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Burkart, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per the criteria in Requirement R3, Part 3.2.1, FR data is not required for circuit breaker 3.

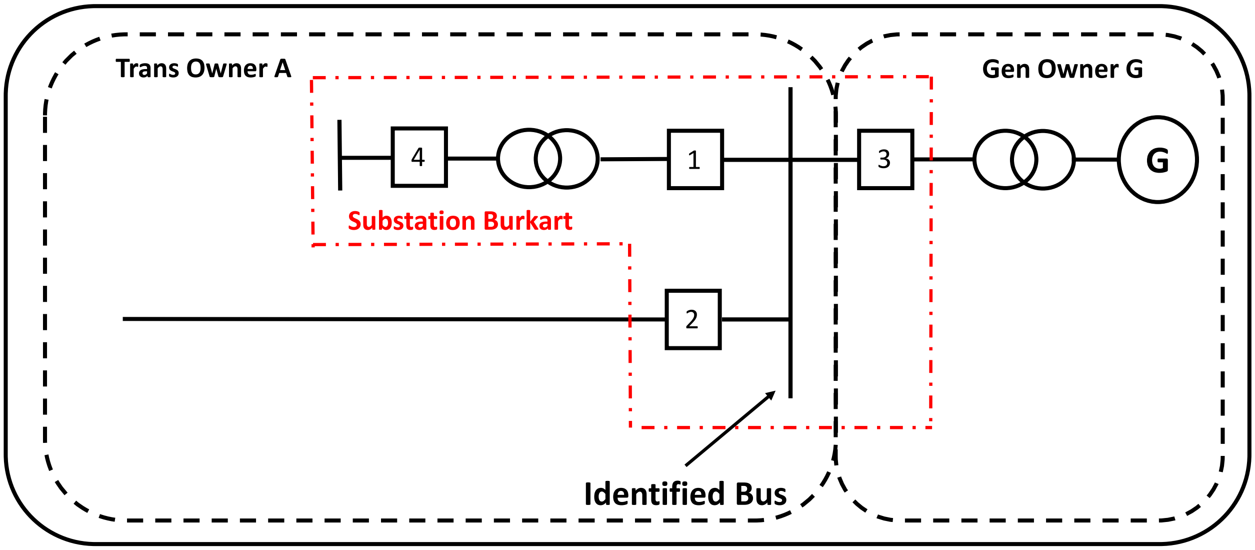

Figure 5: Generator Interconnection to Straight Bus

For a generator interconnection to a ring bus, as shown in Figure 6, Transmission Owner A is responsible for SER data for circuit breakers 1, 2, and 3. The Transmission Owner A is required to record FR data for contributions from the transmission line (circuit breakers 2 and 3) and transformer (circuit breakers 1 and 2). However, per the criteria in Requirement R3, Part 3.2.1, FR data is not required for contribution from the generator.

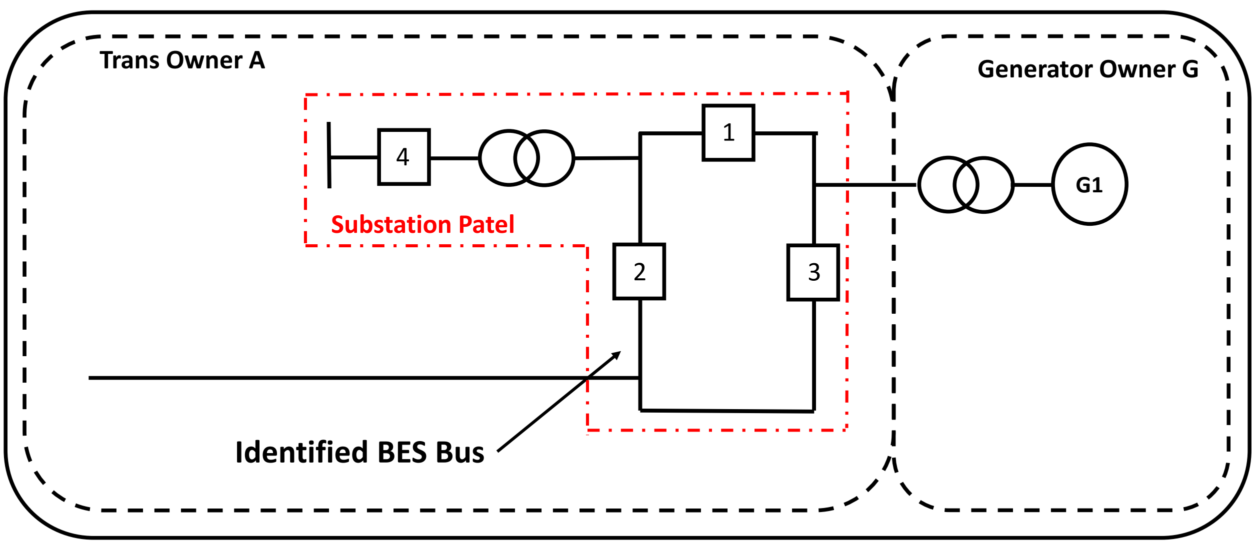

Figure 6: Generator Interconnection to Ring Bus

Figure 7 shows another example of a generator interconnection where generating units/a plant is connected via a transmission line to the identified BES bus for which SER and FR data is required. Circuit breakers 1, 2 and 3 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breaker 3 and a short transmission line to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Key, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The Generator Owner G is owner of circuit breaker 3. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breaker 3, then Generator Owner G must be notified that SER data is required for circuit breaker 3. Per rationale for Requirement R3, FR data is not required for circuit breaker 3 because the transmission line (connecting the generating plant to the Transmission System) is used to exclusively export energy from the generating plant.

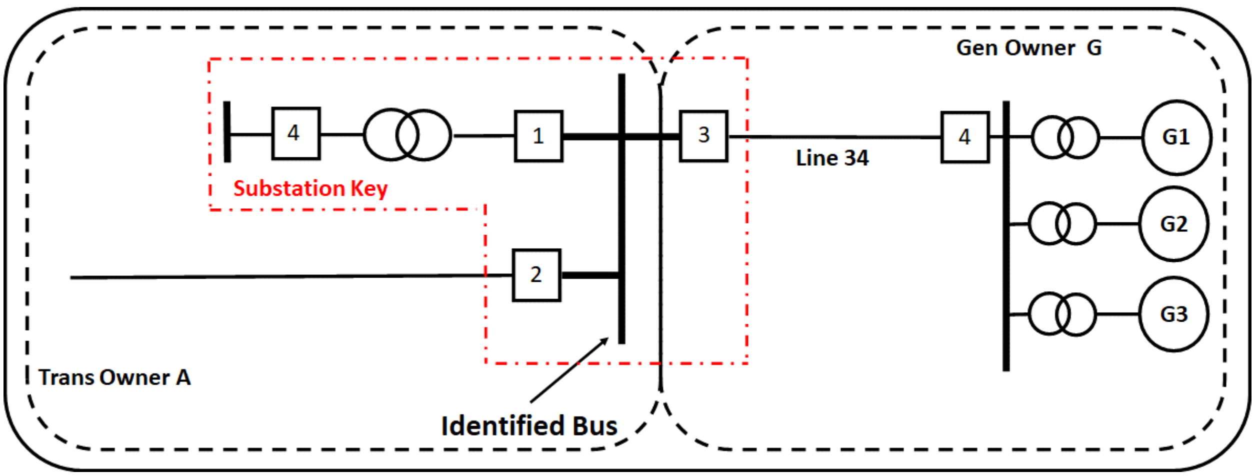

Figure 7: Generator Interconnection via Line 34

Figure 8 shows an example of a generator interconnection via multiple lines that creates a transmission loop. Circuit breakers 1, 2, 3 and 5 are BES Elements that are directly connected to the identified BES bus. Transmission Owner A owns the physical bus as well as circuit breakers 1 and 2. Generator Owner G owns directly connected circuit breakers 3 and 5 and both transmission lines to the generating plant. All equipment (physical bus(es) and circuit breakers) that comprise a BES bus is located within the same physical space, i.e., substation Milan, regardless of ownership.

Transmission Owner A is responsible for SER and FR data for circuit breakers 1 and 2. The loop is created by Line 36 and Line 57. These lines are exclusively used to export power from the generating plant to the transmission system. The FR data is not required for these lines, however, SER data is required on circuit breakers 3 and 5. Per Requirement R1, Part 1.2, if Transmission Owner A does not record SER data for circuit breakers 3 and 5, then Generator Owner G must be notified that SER data is required for circuit breakers 3 and 5.

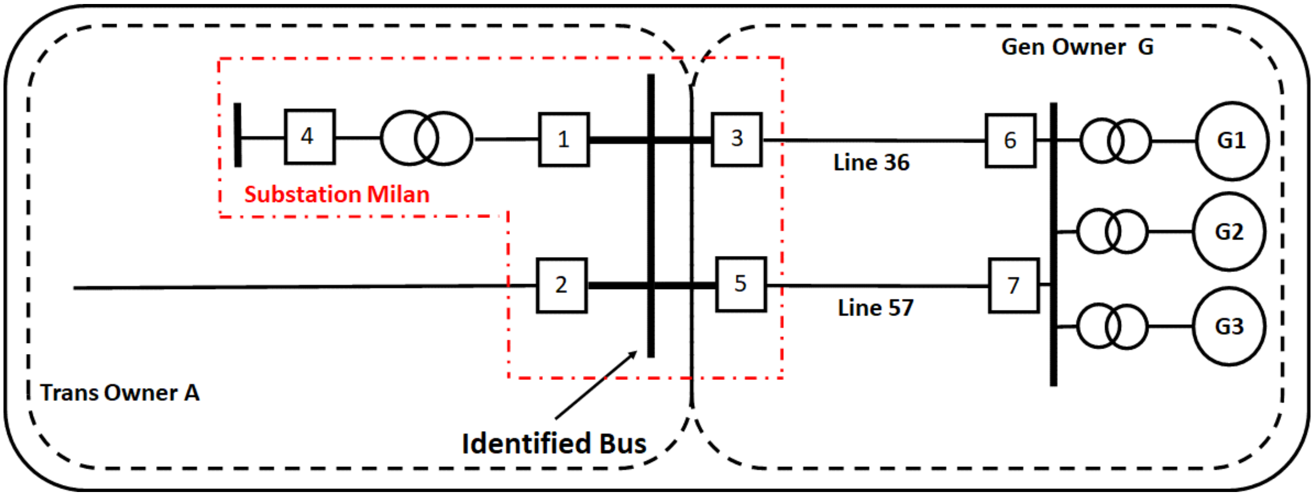

Figure 8: Generator Interconnection via Multiple Lines

The following is an example of a notification provided by Transmission Owner A to Transmission Owner B:

Notification details:

FROM	Transmission Owner A
TO	Transmission Owner B
CC	
BCC	NA
SUBJECT	PRC-002 R1.2 2027 Notification_TransmissionOwnerB

Greetings,

In accordance with NERC Standard PRC-002-4, Requirement R1.1, Transmission Owner A has identified its BES buses for which sequence of events recording (SER) and fault recording (FR) data is required, using the methodology in Attachment 1.

Per Requirement R1.2, you are being notified that the below BES Elements have been determined to be directly connected to one of the buses identified in R1.1 and owned by Transmission Owner B. Transmission Owner A does not have SER and/or FR data on the BES Elements listed below, and thus Transmission Owner B is required to have SER and/or FR data on the following BES Elements:

Transmission Owner A Bus (R1.1)	Directly connected BES Element owned by Transmission Owner B	BES Element Type	Data Required
KEALY 500 kV	Breakers: 3	Breaker	SER
MAGEE 500 kV	Breakers: 3	Breaker	SER
MILAN 500 kV	Lines: 36, 57	Line	FR
MILAN 500 kV	Breakers: 3, 5	Breaker	SER

BURKART 500kV	Breakers: 3	Breaker	SER
EXAMPLE 500kV	Transformer	Transformer	FR

If you have any questions about this notification, analysis or otherwise, please email Transmission Owner A.

Thank you,
Transmission Owner A

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.

Rationale for Requirement 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 directly connected to a BES bus. Change of state of circuit breaker position and 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.

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.

Examples in Figures 9, 10 and 11 show BES Elements directly connected to an identified BES bus that are required to have SER data captured.

Rationale for Requirement 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.

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 directly 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 directly 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.

Examples in Figures 9, 10, and 11 show BES Elements directly connected to an identified BES bus that are required to have FR data captured.

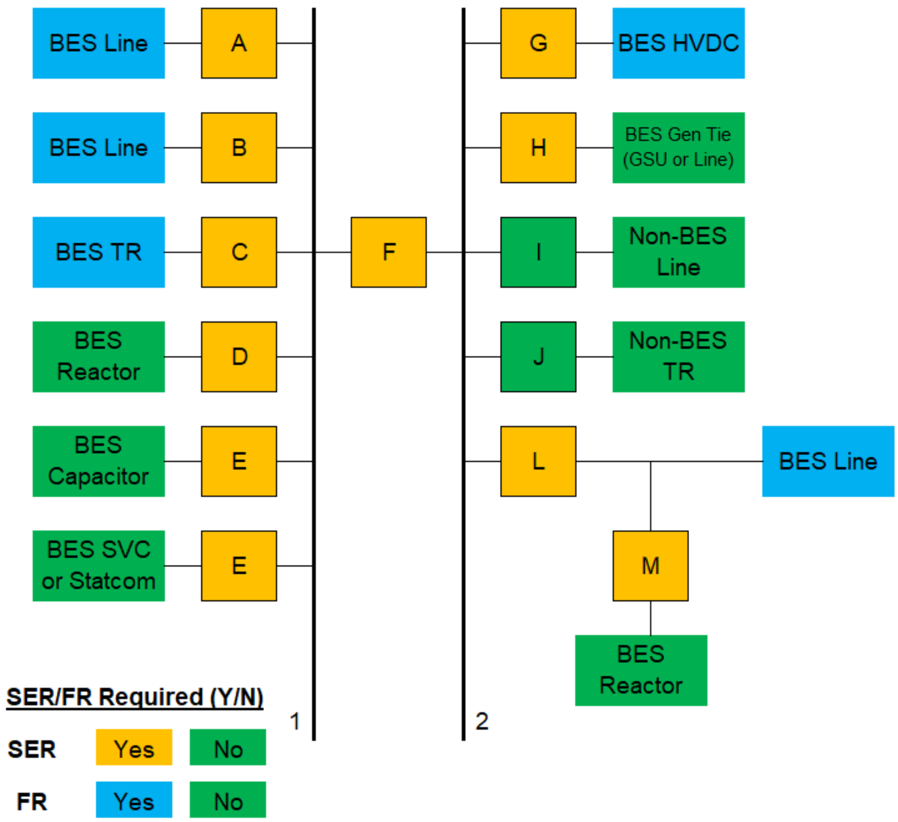

Figure 9: Straight BES Buses

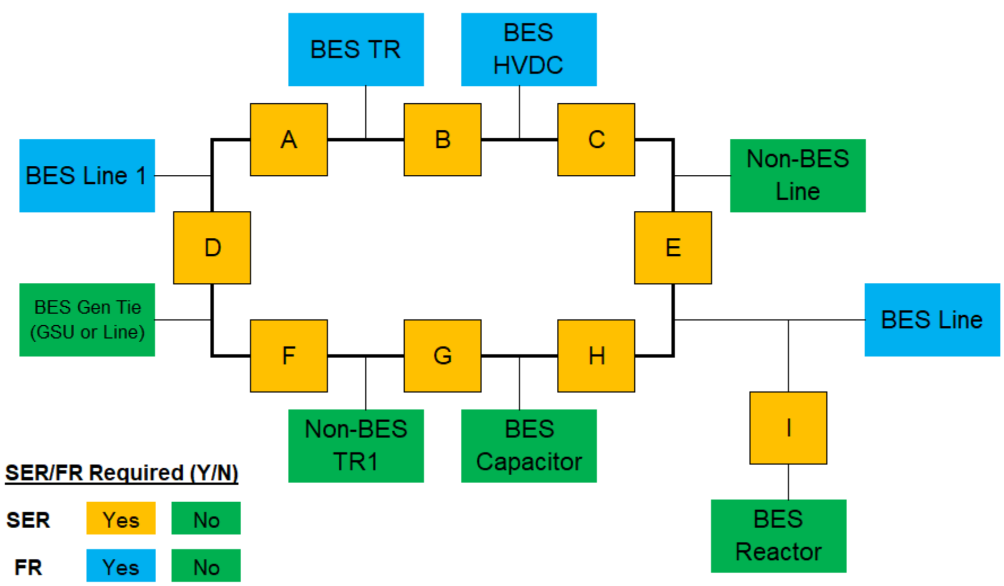

Figure 10: Ring BES Bus

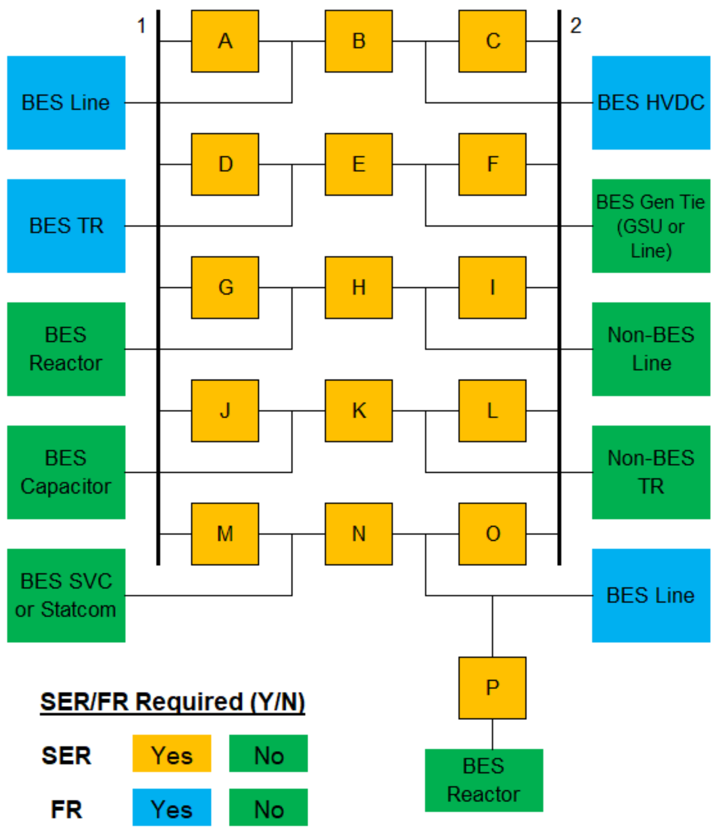

Figure 11: Breaker and Half BES Bus

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.

<u>Voltage Recordings</u>
Voltages are to be recorded or accurately determined at applicable BES buses

Rationale for Requirement 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.

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.

Rationale for Requirement 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 Reliability Coordinator 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 Reliability Coordinator from performing this re-evaluation more frequently to capture updated BES Elements.

The Reliability Coordinator must notify all owners of the selected BES Elements that DDR data is required for this standard. The Reliability Coordinator 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 Reliability Coordinator. Data for each BES Element as defined by the Reliability Coordinator 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 Reliability Coordinators, each Reliability Coordinator 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 Reliability Coordinator will determine which entity will provide the data. The Reliability Coordinator 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 Reliability Coordinators. It is intended that each Reliability Coordinator 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.

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 Reliability Coordinator 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 Reliability Coordinator Area, DDR data capability is required. If a Reliability Coordinator 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 Reliability Coordinator 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 Reliability Coordinator 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.).

Rationale for Requirement 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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

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 Reliability Coordinator 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-002-4 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.

Rationale for Requirement 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 eitherthe 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.

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-002-4 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Rationale for Requirement 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).

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.

Rationale for Requirement 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.

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.

Rationale for Requirement 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.

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 one millisecond, uncertainty being a quantitative descriptor.

Rationale for Requirement 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 11.2, 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. A10-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.

This requirement directs the applicable entities, upon requests from the Reliability 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 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 11.2 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 11.1 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 synchrophasor 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.

Rationale for Requirement 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.

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.

Rationale for Requirement R13

Three (3) calendar years of completing a re-evaluation or receiving notification by the Transmission Owner or the Reliability Coordinator is more time than provided in the Implementation Plan of previous versions of this NERC Reliability Standard. The Implementation Plan of previous versions of this Standard provided three years. This time period pertains to those new Elements appearing on the list due to re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4. Having the period built into Requirement R13 maintains visibility of the required time to install monitoring equipment to collect necessary data.

Requirement R13 requires the Transmission Owner and Generator Owner to install monitoring equipment to record required data within three (3) calendar years of completing a re-evaluation or receiving notification that new Elements were identified during re-evaluation pursuant to Requirement R1, Part 1.3 or Requirement R5, Part 5.4 by the Transmission Owner or the Reliability Coordinator.

Standards Announcement

Project 2021-04 Modifications to PRC-002

Final Ballots Open through December 16, 2022

Now Available

Final ballots are open through **8 p.m. Eastern, Friday, December 16, 2022** for the following standard and implementation plan:

- PRC-002-4 – Disturbance Monitoring and Reporting Requirements
- Implementation Plan

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Ben Wu (via email) or at 470-542-6882.

North American Electric Reliability Corporation
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 FN 3 ST
Voting Start Date: 12/7/2022 8:22:36 AM
Voting End Date: 12/16/2022 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 243
Total Ballot Pool: 290
Quorum: 83.79
Quorum Established Date: 12/7/2022 9:17:09 AM
Weighted Segment Value: 96.43

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	81	1	60	0.952	3	0.048	0	5	13
Segment: 2	7	0.5	5	0.5	0	0	0	0	2
Segment: 3	67	1	53	0.964	2	0.036	0	2	10
Segment: 4	15	1	11	1	0	0	0	0	4
Segment: 5	68	1	48	0.923	4	0.077	0	4	12
Segment: 6	46	1	38	0.95	2	0.05	0	2	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	6	0.4	4	0.4	0	0	0	0	2
Totals:	290	5.9	219	5.689	11	0.211	0	13	47

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Alain Mukama		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker		None	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Western Area Power Administration	Sean Erickson		Abstain	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		None	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		None	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Abstain	N/A
3	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Arkansas Electric Cooperative Corporation	Alice Wright		None	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya Vannorman	Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Buckeye Power, Inc.	Ryan Strom		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Affirmative	N/A
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	John Cook	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	N/A
5	Orlando Utilities Commission	Dania Colon		Abstain	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Duke Energy	John Sturgeon		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		None	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Abstain	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2021-04 Modifications to PRC-002 | Draft 1 Implementation Plan FN 3 OT
Voting Start Date: 12/7/2022 8:22:00 AM
Voting End Date: 12/16/2022 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 242
Total Ballot Pool: 287
Quorum: 84.32
Quorum Established Date: 12/7/2022 9:17:06 AM
Weighted Segment Value: 96.11

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	81	1	59	0.937	4	0.063	0	5	13
Segment: 2	7	0.5	5	0.5	0	0	0	0	2
Segment: 3	67	1	53	0.964	2	0.036	0	2	10
Segment: 4	13	1	11	1	0	0	0	0	2
Segment: 5	67	1	47	0.922	4	0.078	0	4	12
Segment: 6	46	1	37	0.949	2	0.051	0	3	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	6	0.4	4	0.4	0	0	0	0	2
Totals:	287	5.9	216	5.67	12	0.23	0	14	45

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	LaTroy Brumfield		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Jennifer Loiacano		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Colorado Springs Utilities	Mike Braunstein		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		None	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Alain Mukama		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Affirmative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	James Baldwin		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		None	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker		None	N/A
1	Orlando Utilities Commission	Aaron Staley		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Abstain	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		None	N/A
1	Western Area Power Administration	Sean Erickson		Abstain	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Andrew Gallo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar		Affirmative	N/A
2	ISO New England, Inc.	John Pearson		None	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Michael Dieringer		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Schroeder		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		None	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Hydro One Networks, Inc.	Paul Malozewski		None	N/A
3	Imperial Irrigation District	Glen Allegranza	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	James Mearns	None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Abstain	N/A
3	Portland General Electric Co.	Adam Menendez		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Abshier		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Austin Energy	Tony Hua		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Florida Municipal Power Agency	Dan O'Hagan	LaKenya Vannorman	Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	James Mearns	None	N/A
4	Oklahoma Municipal Power Authority	Michael Watt		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	Acciona Energy North America	Krys Rootham		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Buckeye Power, Inc.	Ryan Strom		None	N/A
5	California Department of Water Resources	ASM Mostafa		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Jacalynn Bentz		Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	Hydro-Qu?bec Production	Carl Pineault		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	National Grid USA	Robin Berry		Affirmative	N/A
5	NB Power Corporation	David Melanson		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Summer Esquerre		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	John Cook	Scott Brame	Affirmative	N/A
5	Northern California Power Agency	Jeremy Lawson	James Mearns	None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	N/A
5	Orlando Utilities Commission	Dania Colon		Abstain	N/A
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Nicole Goi	Tim Kelley	Affirmative	N/A
5	Salt River Project	Jennifer Bennett	Israel Perez	Affirmative	N/A
5	Santee Cooper	Marty Watson		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	N/A
5	Southern Company - Southern Company Generation	Jim Howell, Jr.		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tallahassee Electric (City of Tallahassee, FL)	Karen Weaver		None	N/A
5	TransAlta Corporation	Ashley Scheelar		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	Vistra Energy	Daniel Roethemeyer		Affirmative	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP	Justin Kuehne		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Black Hills Corporation	Claudine Bates		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Jennifer Flandermeyer	Alan Kloster	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Affirmative	N/A
6	Great River Energy	Donna Stephenson		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Simon Tanapat-Andre		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet	James Mearns	None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Joseph Neglia		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	M LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Glenda Horne		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Chrystal Dean		Abstain	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
10	Midwest Reliability Organization	William Steiner		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		None	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit G

Standard Drafting Team Roster, Project 2021-04 Cold Weather

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

SAR Drafting Team Roster

Project 2021-04 Modifications to PRC-002-2

	Name	Entity
Chair	Manish Patel	Southern Company Services
Vice Chair	Christopher Milan	NewFields
Members	Bret Garner Burford	American Electric Power
	Don Burkart	Consolidated Edison of New York
	Tracy Kealy	Bonneville Power Administration
	Amy Key	MidAmerican Energy Company
	Terry Volkmann	Volkmann Consulting
	Jacob Magee	Transmission Asset Management
NERC Staff	Ben Wu – Senior Standards Developer	North American Electric Reliability Corporation
	Marisa Hecht – Legal	North American Electric Reliability Corporation
	Lauren Perotti – Legal	North American Electric Reliability Corporation