Normes de fiabilité et leur annexe Québec en suivi des modifications en suivi de la décision D-2024-096 (version anglaise)

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

This is a final posting.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 20, 2021
SAR posted for comment	June 14, 2021 – July 13, 2021

Anticipated Actions	Date
45-day formal comment period with ballot	August 1, 2023 – September 14, 2023
25-day formal or informal comment period with additional ballot	March 18, 2024 – April 11, 2024
15-day formal or informal comment period with additional ballot	May 31, 2024 – June 17, 2024
22-day formal or informal comment period with additional ballot	July 22, 2024 – August 12, 2024
7 day final ballot	September 12, 2024 – September 18, 2024
Board adoption	October 15, 2024

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.~~ The terms Inverter-Based Resource (IBR) refer to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of Inverter-Based Resource is:

Inverter-Based Resource (IBR): A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-54
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
   - **4.2. Facilities:** BES Elements, excluding Inverter-Based Resources.[1]
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-002-54, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[2] 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-002-54, 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.

[1] Disturbance monitoring and reporting requirements for Inverter-Based Resources are addressed in PRC-028.

[2] 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 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 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. Synchronous ~~G~~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[3] 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

[3] 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.

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 either in CSV format with appropriate headers or 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.

~~**11.4.**~~**11.5.** DDR data will be provided either in CSV format with appropriate headers or 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.**~~**11.6.** 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, upon~~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 within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

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: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. ~~Data~~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: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with associated Reliability Standard.

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

~~**1.4. Additional Compliance Information**~~

~~None.~~

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	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 or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 30 calendar days and less than or equal to 60 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other 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 or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3, but was late by greater than 60 calendar days and less than or equal to 90 calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other 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	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	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	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent, but less than 100 percent of the total recording parameters~~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 parameters~~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 parameters~~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 parameters~~properties~~ as specified in Requirement R4.
R5	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	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	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.	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.	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.	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	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, which is the product of the total number of applicable BES Elements and the number of specified electrical	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, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each	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, which is the product of the total number of applicable BES Elements and the number of specified electrical	The Transmission Owner ~~failed to~~ hadve DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical

	quantities for each applicable BES Element ~~for all applicable BES Elements~~.	applicable BES Element ~~for all applicable BES Elements~~.	quantities for each applicable BES Element ~~for all applicable BES Elements~~.	quantities for each applicable BES Element.
R7	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, which is -the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element~~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, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element ~~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, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element ~~for all applicable BES Elements~~.	The Generator Owner ~~failed to~~ had~~ve~~ DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for less than 60 percent of the total required electrical quantities, which is the product of the total number of applicable BES Elements and the number of specified electrical quantities for each applicable BES Element.
R8	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 they own as	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.	determined in Requirement R5.	
R9	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	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	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided the	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 provided	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 ~~failed to~~

	the requested data more than one to 10 calendar days late~~30 calendar days, but less than or equal to 40 calendar days after the request, unless an extension was granted by the requesting authority~~. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent, but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	requested data more than 11 to 20 calendar days late~~40 calendar days, but less than or equal to 50 calendar days after the request, unless an extension was granted by the requesting authority~~. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~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 requested data more than 21 to 30 calendar days late~~50 calendar days, but less than or equal to 60 calendar days after the request, unless an extension was granted by the requesting authority~~. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~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.	provided the requested data more than 30 calendar days late~~60 calendar days after the request, unless an extension was granted by the requesting authority~~. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.6~~5~~ provided less than or equal to 70 percent of the data in the proper data format.
R12	The Transmission Owner or Generator Owner as directed by Requirement	The Transmission Owner or Generator Owner as directed by Requirement	The Transmission Owner or Generator Owner as directed by Requirement	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.	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.	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.	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		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	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	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

		Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	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.	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-002-5~~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-002-5~~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	February 16, 2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14, 2023	FERC Oder Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14, 2023	Effective Date	April 1, 2024
5	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 Bulk Electric System (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. Refer to section 4.2 Facilities for exclusion.

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.

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 Disturbance Monitoring Equipment (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[4]

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

[4] "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

Appendix PRC-002-~~4~~5-QC-1
Specific provisions applicable in Québec for standard
PRC-002-~~4~~5 – Disturbance Monitoring and Reporting Requirements

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of this appendix must be read jointly for comprehension and interpretation purposes. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** No specific provisions.

2. **Number:** No specific provisions.

3. **Purpose:** No specific provisions.

4. **Applicability:** In the application of this standard, all reference to the term "Bulk Electric System" or "BES" shall be replaced by the terms "Main Transmission System" or "RTP" respectively.

   The Facilities subject to this standard are the Facilities of the Main Transmission System (RTP).

   4.1. Functional Entities:

   No specific provisions.

   4.2. Facilities:

   No specific provisions.

5. **Effective Date:**

   5.1. Adoption of the standard by the Régie de l'énergie: ~~June 20, 2024~~February 10, 2026

   5.2. Adoption of the appendix by the Régie de l'énergie: ~~June 20, 2024~~ February 10, 2026

   5.3. Effective date of the standard and its appendix in Québec: ~~October 1, 2026~~February 17, 2026

~~**Requirements**~~	~~**Applicability**~~	~~**Date of enforcement in Québec**~~
~~R1 to R12~~	~~100% of applicable facilities already subject to PRC-002-2~~	~~October 1, 2026~~
~~R2 to R4~~ ~~R6 to R11~~	~~100% of facilities newly subjected to PRC-002-4 identified in Requirement R1 or R5~~	~~Within three (3) years following the notification by the Transmission Owner or the Reliability Coordinator~~

B. Requirements and Measures

No specific provisions.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

In Québec, "Compliance Enforcement Authority" means the Régie de l'énergie in its roles of monitoring and enforcing compliance with respect to the Reliability Standard and to this appendix.

1.2. ~~Data~~ Evidence Retention

No specific provisions.

~~Erratum correction: The first sentence of this section in the Reliability Standard should be removed as it refers to compliance enforcement authorities in subsection C1.1 "Compliance Enforcement Authority".~~

1.3. Compliance Monitoring and Enforcement Program~~:~~

~~No specific provisions.~~The Régie de l'énergie establishes the monitoring processes used to evaluate data or information for the purpose of determining compliance or non-compliance with the reliability standard and with this appendix.

~~**1.4. Additional Compliance Information**~~

~~No specific provisions.~~

Violation Severity Levels

No specific provisions.

D. Regional Variances

No specific provisions.

E. Interpretations

No specific provisions.

F. Associated Documents

No specific provisions.

G. References

No specific provisions.

Attachment 1

No specific provisions.

Attachment 2

No specific provisions.

High Level Requirement Overview

No specific provisions.

Version History

Version	Date	Action	Change Tracking
1	~~June 20, 2024~~ February 10, 2026	New Appendix as per decision ~~D-2024-060~~ D-2026-010.	New

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
2. **Number:** PRC-028-1
3. **Purpose:** To have adequate data available from Inverter-Based Resources to evaluate Inverter-Based Resource ride-through performance during System Disturbances and to provide data for Inverter-Based Resource model validation.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Generator Owner
   - **4.2. Facilities:**
     - **4.2.1** BES Inverter-Based Resources
     - **4.2.2** Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV
5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

R1. Each Generator Owner shall have sequence of event recording (SER) data for the following Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- **1.1.** Circuit breaker position (open/close) for circuit breakers associated with the main power transformer(s)[1], collector bus(es), shunt static and dynamic reactive device(s), and AC-DC and DC-AC converters, if any, in case of VSC HVDC system with a dedicated connection to Inverter-Based Resource.
- **1.2.** For IBR units[2] in commercial operation[3] after the effective date of this standard, the following data shall be recorded when triggered by ride-through operation or tripping of an IBR unit.

[1] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for Inverter-Based Resources. In case of dedicated VSC HVDC system connecting to an Inverter-Based Resource, a transformer isolating the DC-AC converter from the transmission system is also considered a main power transformer.

[2] IBR unit includes the inverter, converter, wind turbine generator, or high voltage direct current converter connecting generating resource to alternating current Transmission network.

[3] Commercial operation means achievement of this designation indicating that the facility has received all approvals necessary for operation after completion of initial start-up testing.

1.2.1. All fault codes.

1.2.2. All fault alarms.

1.2.3. High and low voltage ride-through mode status.

1.2.4. High and low frequency ride-through mode status.

1.3. For IBR units in commercial operation before the effective date of this standard, if capable, the following data shall be recorded when triggered by ride-through operation or tripping of an IBR unit.

1.3.1. All fault codes.

1.3.2. All fault alarms.

1.3.3. High and low voltage ride-through mode status.

1.3.4. High and low frequency ride-through mode status.

M1. The Generator Owner has evidence (electronic or hard copy) of data, as applicable, as specified in Requirement R1. Evidence may include, but is not limited to: (1) actual data recordings; or (2) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings. The evidence to show IBR unit capability to record fault codes, alarms, or ride-through mode status may include, but is not limited to: (1) equipment specification, (2) letter from equipment manufacturer, or (3) documents describing lack of recording capability.

R2. Each Generator Owner shall have triggered fault recording (FR) data to determine the following electrical quantities for Elements that it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. High-side of the main power transformer FR data:

2.1.1. Phase-to-neutral voltage for each phase.

2.1.2. Each phase current and the residual or neutral current.

2.1.3. Real and Reactive Power expressed on a three-phase basis.

2.2. Collector feeder breaker FR data:

2.2.1. Phase-to-neutral voltage for each phase.

2.2.2. Each phase current and the residual or neutral current.

2.2.3. Real and Reactive Power expressed on a three-phase basis.

2.3. Shunt dynamic reactive device FR data:

2.3.1. Phase-to-neutral voltage for each phase.

2.3.2. Each phase current and the residual or neutral current.

2.3.3. Reactive Power output expressed on a three-phase basis.

M2. The Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R2. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (3) station or equipment drawings.

R3. Each Generator Owner shall have FR data as specified in Requirement R2 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. High-side of the main power transformer FR data:

3.1.1. 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 2.0 seconds for the same trigger point.

3.1.2. A minimum recording rate of 64 samples per cycle.

3.1.3. Trigger settings for at least the following:

3.1.3.1. Neutral (residual) overcurrent.

3.1.3.2. AC phase overvoltage and undervoltage.

3.1.3.3. Overfrequency and underfrequency

3.2. Collector feeder breaker FR data:

3.2.1. 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 2.0 seconds for the same trigger point.

3.2.2. A minimum recording rate of 64 samples per cycle.

3.2.3. Trigger settings for at least the following:

3.2.3.1. Neutral (residual) overcurrent, if applicable.

3.2.3.2. AC phase overvoltage and undervoltage.

3.2.3.3. Overfrequency and underfrequency.

3.3. Shunt dynamic reactive device FR data:

3.3.1. 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 2.0 seconds for the same trigger point.

3.3.2. A minimum recording rate of 64 samples per cycle.

3.3.3. Trigger settings for at least the following:

3.3.3.1. Neutral (residual) overcurrent.

3.3.3.2. AC phase overvoltage and undervoltage.

M3. The Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R3. Evidence may include, but is not limited to: (1) actual data recordings or derivations, or (2) documents describing the device specification and device configuration or settings.

R4. Each Generator Owner shall have continuous dynamic disturbance recording (DDR) data and storage to determine the following electrical quantities for each main power transformer(s) it owns: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. One phase-to-neutral or positive sequence voltage on high-side of the main power transformer(s).

4.2. The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R4, Part 4.1, or the positive sequence current.

4.3. Real Power and Reactive Power flows expressed on a three-phase basis corresponding to each main power transformer(s) where current measurements are required.

4.4. Frequency of any one of the voltage(s) in Requirement R4, Part 4.1.

M4. The Generator Owner has evidence (electronic or hard copy) of continuous DDR data recording and storage to determine electrical quantities as specified in Requirement R4. Evidence may include, but is not limited to: (1) actual data recordings or derivations; or (2) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (3) station drawings.

R5. Each Generator Owner responsible for DDR data for the electrical quantities identified in Requirement R4 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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

5.2. Output recording rate of electrical quantities of at least 60 times per second.

M5. The Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R5. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R5, Part 5.1; R5, Part 5.2); or (2) actual data recordings (R5, Part 5.2).

R6. Each Generator Owner shall time synchronize all SER, FR, and DDR data to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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

6.2. The IBR unit synchronized device clock accuracy within ± 100 milliseconds of UTC. For all other devices, synchronized device clock accuracy within ± 1 milliseconds of UTC.

M6. The Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R6. 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.

R7. Each Generator Owner shall provide all requested SER, FR, and DDR data to its Transmission Planner, Planning Coordinator, Transmission Operator, Balancing Authority, Reliability Coordinator, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1. Data shall be retrievable for the period of 20 calendar days, inclusive of the day the data was recorded.

7.2. Data subject to Part 7.1 shall be provided within 15 calendar days of a request unless an extension is granted by the requestor.

7.3. SER data shall be provided in ASCII[4] Comma Separated Value (CSV) format following Attachment 1.

7.4. FR data shall be provided either in CSV format with appropriate headers or 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.

7.5. DDR data shall be provided either in CSV format with appropriate headers or 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.

7.6. Data files shall 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.

M7. The Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R7. Evidence may include, but is not limited to: (1) actual data recordings; (2) dated transmittals to the requesting entity with formatted records; or (3) documents describing data storage capability, device specification, configuration, or settings.

R8. Each Generator Owner shall, upon the discovery of a failure of the recording capability for the SER, FR, or DDR data: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability within 90 calendar days, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity within 90 calendar days and then implement it according to CAP timeline.

[4] American Standard Code for Information Interchange

M8. The Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R8. Evidence may include, but is not limited to: (1) dated reports of the discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated Corrective Action Plan transmittals to the Regional Entity and evidence of Corrective Action Plan implementation.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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 Generator Owner 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 Generator Owner shall retain evidence, as per Requirements R1 through R8, for three calendar years.

If a Generator Owner 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: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 80 percent, but less than 100 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 70 percent, but less than or equal to 80 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had more than 60 percent, but less than or equal to 70 percent of the circuit breaker(s) identified in Requirement R1.	Each Generator Owner as directed by Requirement R1 to have the required SER data had less than or equal to 60 percent of the circuit breaker(s) identified in Requirement R1.
R2	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had FR data as directed by Requirement R2, Parts 2.1, 2.2, and 2.3 that covers less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.
R3	The Generator Owner had FR data that meets more	The Generator Owner had FR data that meets more	The Generator Owner had FR data that meets more	The Generator Owner had FR data that meets less

	than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R3.	than 70 percent, but less than or equal to 80 percent of the total recording parameters as specified in Requirement R3.	than 60 percent, but less than or equal to 70 percent of the total recording parameters as specified in Requirement R3.	than or equal to 60 percent of the total recording parameters as specified in Requirement R3.
R4	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 that covered more than 80 percent, but less than 100 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 70 percent, but less than or equal to 80 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for more than 60 percent, but less than or equal to 70 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.	The Generator Owner had DDR data as directed by Requirement R4, Parts 4.1 through 4.4 for less than or equal to 60 percent of the total required electrical quantities, which is the product of the total number of monitored Elements and the number of specified electrical quantities for each Element.
R5	The Generator Owner had DDR data that meets more than 80 percent, but less than 100 percent of the total recording parameters as specified in Requirement R5.	The 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 R5.	The 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 R5.	The Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R5.

R6	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 90 percent, but less than 100 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 80 percent, but less than or equal to 90 percent of the Elements.	The Generator Owner had time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for more than 70 percent, but less than or equal to 80 percent of the Elements.	The Generator Owner failed to have time synchronized SER, FR, or DDR data per Requirement R6, Parts 6.1 and 6.2 for less than or equal to 70 percent of the Elements.
R7	The Generator Owner as directed by Requirement R7 provided more than 90 percent, but less than 100 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data one to 10 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 90 percent of the data, but less than 100 percent of	The Generator Owner as directed by Requirement R7 provided more than 80 percent, but less than or equal to 90 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data 11 to 20 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 80 percent of the data, but less than or equal to 90 percent	The Generator Owner as directed by Requirement R7 provided more than 70 percent, but less than or equal to 80 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data 21 to 30 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided more than 70 percent of the data, but less than or equal to 80	The Generator Owner as directed by Requirement R7 failed to provide less than or equal to 70 percent of the requested data. OR The Generator Owner as directed by Requirement R7, Part 7.2 provided the requested data more than 30 calendar days late. OR The Generator Owner as directed by Requirement R7, Parts 7.3 through 7.6 provided less than or equal to 70 percent of the data in the proper data format.

	the data in the proper data format.	of the data in the proper data format.	percent of the data in the proper data format.	
R8	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days 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 Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days 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 Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days 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 Generator Owner as directed by Requirement R8 submitted a Corrective Action Plan to the Regional Entity but failed to implement it.	The Generator Owner as directed by Requirement R8 was unable to restore recording capability within 90 calendar days and provided a Corrective Action Plan to the Regional Entity more than 120 calendar days after discovery of the failure. OR Generator Owner as directed by Requirement R8 failed to restore the recording capability within 90 calendar days and failed to submit a Corrective Action Plan to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-028-1: Implementation Plan.

NERC Reliability Standard PRC-028-1: Technical Rationale.

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.

IEEE Std 2800-2022: IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems.

Multiple Solar PV Disturbances in CAISO, Joint NERC and WECC Staff Report, April 2022.

NERC Reliability Standard PRC-002-5.

Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021, Joint NERC and Texas RE Event Report, September 2021.

Odessa Disturbance, Texas Event: June 4, 2022, Joint NERC and Texas RE Event Report, December 2022.

Version History

Version	Date	Action	Change Tracking
1	October 8, 2024	Adopted by NERC Board of Trustees	

Attachment 1

Sequence of Events Recording (SER) Data Format

(Requirement R7, Part 7.3)

Date, Time, Local Time Code, Plant Name, Device[5], State[6]

08/27/23, 23:58:57.110, -5, Plant name 1, Breaker 1, Close

08/27/23, 23:58:57.082, -5, Plant name 2, Breaker 2, Close

08/27/23, 23:58:57.217, -5, Plant name 1, IBR unit 1, undervoltage ride-through mode

08/27/23, 23:58:57.214, -5, Plant name 2, IBR unit 2, dc overcurrent trip

[5] Device name may include specific names of breakers or IBR units as appropriate.

[6] Breaker status and any other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is acceptable. For IBR unit level data, fault codes, alarms, change in operating mode etc., are also acceptable.

Appendix PRC-028-1-QC-1
Specific provisions applicable in Québec for standard
PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of this appendix must be read jointly for comprehension and interpretation purposes. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** No specific provisions.

2. **Number:** No specific provisions.

3. **Purpose:** No specific provisions.

4. **Applicability:** In the application of this standard, all reference to the term "Bulk Electric System" or "BES" shall be replaced by the terms "Main Transmission System" or "RTP" respectively.

~~The Facilities subject to this standard are the Facilities of the Main Transmission System (RTP).~~

4.1. Functional Entities:

No specific provisions.

4.2. Facilities:

4.2.1 RTP Inverter-Based Ressources. ~~No specific provisions~~.

4.2.2 Non-RTP Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 50 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 44 kV.

5. **Effective Date:**

5.1. Adoption of the standard by the Régie de l'énergie: ~~MM-DD-YYYY~~February 10, 2026

5.2. Adoption of the appendix by the Régie de l'énergie: ~~MM-DD-YYYY~~February 10, 2026

5.3. Effective date of the standard and its appendix in Québec: ~~MM-DD-YYYY~~ February 17, 2026

Requirements	Applicability	Date of enforcement in Québec
	RTP Inverter-Based Resources	
R1 to R7	For RTP Inverter-Based Resources in commercial operation[1] on or before the effective date of PRC-028-1, entities shall comply at: • 50% of their RTP Inverter-Based Resources • 100% of their RTP Inverter-Based Resources • Entities that are required to monitor only one (1) RTP Inverter-Based Resource shall comply at 100% of their RTP Inverter-Based Resources	• Within three (3) calendar years of the effective date of PRC-028-1 • Five (5) years after PRC-028-1 approval by the Régie • Within three (3) calendar years of the effective date of PRC-028-1
	For RTP Inverter-Based Resources entering commercial operation after the effective date of PRC-028-1	Within 15 calendar months following the effective date of PRC-028-1 or the commercial operation date, whichever is later.
R8	Entities shall comply	No later than nine (9) months after the effective date of PRC-028-1

[1] Commercial operation means achievement of this designation indicating that the facility has received all approvals necessary for operation after completion of initial start-up testing.

Requirements	Applicability	Date of enforcement in Québec
Non-RTP Inverter-Based Resources		
R1 to R7	For non-RTP Inverter-Based Resources in commercial operation within 15 calendar months following approval of PRC-028-1 by the Régie, -entities shall comply at 100% of their non-RTP Inverter-Based Resources	Five (5) years after approval of PRC-028-1 by the Régie
	For non-RTP Inverter-Based Resources in commercial operation after 15 calendar months following the approval by the Régie	Within 15 calendar months following the effective date of PRC-028-1 or the commercial operation date, whichever is later.
R8	Entities shall comply	Within two (2) calendar years of the effective date of PRC-028-1

Process for Requesting an Extension from Compliance Dates

Each *GO* that owns one or more applicable Inverter-Based Resources that are in commercial operation before the effective date of Reliability Standard PRC-028-1 may request an extension from the above-listed compliance dates if circumstances beyond its control prevent the installation of Disturbance Monitoring Equipment on one or more of its Inverter-Based Resources.

To request an extension, the entity shall develop and submit to its Compliance Enforcement Authority a request for extension that contains at a minimum the following information:

1. Identification of the Inverter-Based Resource(s) for which the entity requests the extension;

2. A plan for installing the Disturbance Monitoring Equipment and a timetable for completion;

3. A description of the circumstances precluding the timely installation of Disturbance Monitoring Equipment and how those circumstances are beyond the control of the entity; and

4. Any other information the entity deems relevant to the Compliance Enforcement Authority's consideration of its request.

Circumstances beyond the entity's control may include supply chain delays associated with the procurement, engineering, installation, or commissioning of disturbance monitoring equipment, inability to secure scheduled outages, or other exceptional circumstances outside the entity's control.

The entity shall provide any information requested by the Compliance Enforcement Authority to validate the information provided above, including any information specified by the Compliance Enforcement Authority in a supporting process document. If the extension request is granted, the entity shall implement the plan in accordance with the provided timetable. Should additional time be required, the entity shall submit an updated request to its Compliance Enforcement Authority.

Requests should be submitted as soon as the entity identifies circumstances impeding the timely implementation of Reliability Standard PRC-028-1, but no later than three months prior to the compliance date for which the entity requests an extension.

B. Requirements and Measures

No specific provisions.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

In Québec, "Compliance Enforcement Authority" means the Régie de l'énergie in its roles of monitoring and enforcing compliance with respect to the Reliability Standard and to this appendix.

1.2. Evidence Retention

No specific provisions.

1.3. Compliance Monitoring and Enforcement Program~~:~~

~~No specific provisions.~~ The Régie de l'énergie establishes the monitoring processes used to evaluate data or information for the purpose of determining compliance or non-compliance with the reliability standard and with this appendix.

Violation Severity Levels

No specific provisions.

D. Regional Variances

No specific provisions.

E. Interpretations

No specific provisions.

F. Associated Documents

No specific provisions.

G. References

No specific provisions.

Attachment 1

No specific provisions.

Version History

Version	Date	Action	Change Tracking
1	~~MM DD YYYY~~February 10, 2026	New Appendix as per decision ~~D-2xxx-xxx~~D-2026-010.	New