Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Nominations for the SAR drafting team members were solicited February 26 – March 9, 2007.
2. The SAR was posted for a 30 day comment period March 22 – April 20, 2007.
3. Nominations for the standard drafting team (SDT) for Project 2007-11 Disturbance Monitoring were solicited June 12 – 25, 2007.
4. The SDT was placed into informal development the fall of 2010
5. The SDT was brought back to formal development January 2013
6. Nominations for two additional standard drafting team (SDT) members were solicited April 12 – 25, 2013.
7. Three additional drafting team members were added May, 2013.
8. Industry webinar May 22, 2013

Description of Current Draft

Anticipated Actions	Anticipated Date
Industry Webinar	May 2013
Technical Workshop/Conference	July/August 2013
45-day Formal Comment Period with a 10 day Ballot	Late August 2013
45-day Formal Comment Period with a 10 day Ballot	Late November 2013
Final ballot	March 2014
BOT adoption	May 2014

Effective Dates

See PRC-002-2 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Dynamic Disturbance Recording (DDR) – The action of recording time sequenced data for dynamic events such as power swings, frequency variations, and abnormal voltage problems.

Fault Recording (FR) – The action of recording time sequenced waveform data for short circuit or failure of Elements resulting in abnormal voltage(s) and / or current(s).

Sequence of Events Recording (SOER) – The action of recording time sequenced data to capture change of status of Elements, which may include protection and control devices.

Generating Plant – One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

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

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

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

4. **Applicability:**

4.1. Functional Entities:

The Responsible Entity to establish a list of monitored BES bus locations and the Elements for Dynamic Disturbance Recording and triggers for the Transmission Owner and Generator Owner, where applicable, is either the:

4.1.1 Planning Coordinator

4.1.2 Reliability Coordinator

4.2. Transmission Owner establishes the bus locations for Fault Recording and Sequence of Events Recording, and is responsible for SOER, FR, or DDR data for each of the Elements they own connected to the established bus locations.

4.3. Generator Owner is responsible for SOER, FR, or DDR data for each of the Elements they own connected to the established bus locations.

Rationale for Functional Entity:

The Responsible Entity has the best technical understanding of a wide area view of the system and is most suited to determine the location and any specialized triggering of Dynamic Disturbance Recording. Transmission Owners and Generator Owners (in coordination and collaboration with its connected Transmission Owners) have the required information to determine the location for Fault Recording, Sequence of Events Recording, and triggers for Facilities within the local systems owned by each.

5. **Background:**

TBD

B. Requirements and Measures

R1. Each Transmission Owner shall establish a list of monitored BES bus locations for Sequence of Events Recording and Fault Recording. The list shall be established by following the selection procedure contained in *PRC-002-2 Attachment 1 – SOER and FR Locations Selection Procedure. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale for R1:

The best sets of event analysis data are produced if SOER and FR is done at every bus on a power system. However this level of recording coverage is unnecessary if SOER and FR data is acquired at appropriate key buses. In a TO's footprint these will include those buses which are the TO's larger or largest buses as they will tend to be at higher voltages, have more BES lines and devices, serve as interconnection points for more or larger generating units, etc. However, SOER and FR locations will also need to be electrically and geographically distributed appropriately, across the TO's service area, to ensure adequate SOER and FR coverage, with no or minimum "gaps". Lastly, some locations will be too small for SOER and FR data from them to be of significant value to determining the cause and contributing factors of a larger system event, so SOER and FR is not warranted from these locations.

Through review of actual BES data the SDT determined that there is good correlation between the ***available short circuit MVA*** at a transmission station bus, and its ***relative size and local importance to the BES*** based upon (i) its voltage level(s), (ii) the number of transmission lines and other devices at the bus, and (iii) the number and size of generating units connected to the bus. To facilitate TOs selecting the appropriate minimum numbers and locations for SOER and FR needed to meet the purpose of PRC-002-2, in a consistent manner, the SDT developed the station-MVA-based procedure included in PRC-002-2 as *Attachment 1 – SOER and FR Locations Selection Procedure*. Selection of SOER and FR locations by TOs using the methodology in the procedure will result in the adequate availability of SOER and FR data for event analysis of significant events, incidents or disturbances on the BES.

Requirement R1 does not require SOER or FR for generating units; instead DDR is required by Requirement R9 for larger generating units or plants. SOER recordings of the opening of primary generator output interrupting devices (*e.g.* synchronizing breaker) may not reliably indicate the actual time that a generator "left the system", for instance when it trips on reverse power after earlier loss of its prime mover (*e.g.* combustion or steam turbine). Also, for event analysis purposes, better information and data at or about generators and their buses is acquired through DDR data versus SOER or FR records.

M1. Text

R2. The Transmission Owner shall review the list established in Requirement R1 at least every five years. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Rationale for R2:

The topology of the transmission system, and other elements (e.g. generating plant locations and size), of the BES may change over time. Requirement R2 recognizes and addresses the need for periodic review of required SOER and FR locations due to those changes.

Requirement R2 is established separately from Requirement R1 to improve the clarity of Requirement R1 and to allow the development of separate VRF and VSLs for Requirement R2.

M2. Text

R3. Each Transmission Owner and Generator Owner shall have Sequence of Events Recording for changes in circuit breaker position (open/close) for each of the circuit breakers they own connected to the bus locations established in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

Rationale for R3:

The intent of this requirement is to specify that Sequence of Events data of the circuit breaker connected to BES bus locations established in Requirement R1.

Change of state of circuit breaker position, time stamped to a common clock at millisecond accuracy, provides the basis for assembling the detailed Sequence of Events timeline of a power system disturbance.

M3. Text

R4. Each Transmission Owner and Generator Owner shall have Fault Recording for each of the Elements they own connected to the bus locations established in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

Rationale for R4:

The intent of this requirement is to specify that Fault Recording data is required at BES bus locations identified established in Requirement R1.

Fault Recording data is used for analyzing system protection operations and circuit breaker performance in response to power system disturbances.

M4. Text

R5. Each Transmission Owner and Generator Owner shall record electrical quantities in order to determine phase-to-neutral voltages for each phase of each line or common bus they own connected to the bus locations established in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

Rationale for R5:

Requirement R5 is needed to reinforce the necessity of capturing data to determine the system phase to neutral voltage effectively and efficiently to support the analysis of the power system response to a disturbance. The system voltage response to a disturbance can be used to track how a disturbance evolves, and what it involves. Is it a solid fault? High-impedance fault? Involve single phase or multi-phase? This can be determined by analyzing this data. The Drafting Team also recognizes that not all quantities needed for power system analysis need to be captured, only the foundation quantities needed from which other quantities can be calculated.

Because of the importance of obtaining this data, Requirement R5 stipulates that the TO and GO record the necessary electrical quantities to make a determination. Not only is this data necessary for fault analysis and review of protection system operations - it also provides an opportunity to check the health of the data measurement devices (PTs, CCPDs, CCVTs, etc.).

M5. Text

R6. Each Transmission Owner and Generator Owner shall record electrical quantities in order to determine each phase current and the residual or neutral current for the following BES Elements they own connected to the bus locations established in Requirement R1:*[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

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

6.2. Transmission Lines.

Rationale for R6:

Requirement R6 is needed to reinforce the necessity of capturing the data to determine each phase and residual (neutral) current effectively and efficiently to support the analysis of the power system response to a disturbance. The responses of system current flows are because they can be used to track how a disturbance evolves, and what it involves. Is it a solid fault? High-impedance fault? Involve single phase or multi-phase? This can be determined by analyzing this data. The Drafting Team also recognizes that not all quantities needed for power system analysis need to be captured, only the foundation quantities needed from which other quantities can be calculated.

Because of the importance of obtaining this data, Requirement R6 stipulates that the TO and GO record the necessary electrical quantities to make a determination. Not only is this data necessary for fault analysis and review of protection system operations - it also provides an opportunity for checking the integrity of current transformers (CTs), and any other primary current measuring devices.

M6. Text

R7. Each Transmission Owner and Generator Owner shall have Fault Recording as specified in Requirement R4 that meets the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

7.1. A single record or multiple records that include either:

•A pre-trigger record length of at least two cycles and a post-trigger record length of at least 50 cycles for the same trigger point.

• At least two cycles of the pre-trigger data, the first three cycles of the fault, and the final cycle of the fault.

7.2 A minimum recording rate of 16 samples per cycle.

Rationale for R7:

This requirement identifies the minimum Fault Recording data and minimum recording rate required to properly analyze a power system short circuit.

Pre and post trigger fault data along with the SOER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection system operations after a fault to determine if the protection system operated as designed. Generally speaking, system faults and the system response to them occur within a very short time period, approximately from 1 to 50 cycles, thus a 50 cycle post trigger record length is adequate. Multiple records allow for legacy microprocessor relays which when time synchronized to a common clock are capable of providing adequate fault record data but not capable of providing fault data in a single record with 50 cycle post trigger data.

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

M7. Text

R8. Each Transmission Owner and Generator Owner shall have Fault Recording as specified in Requirement R4 that triggers for at least the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

8.1. Neutral (residual) overcurrent set at 40% or less of CT secondary rating.

8.2. Monitored phase under-voltage set no lower than 85% of normal operating voltage.

M8. Text

Rationale for R8:

The drafting team recognizes that there are many triggering options available to trigger Fault Recording.

It is the intent of this requirement that each Responsible Entity shall apply these minimum triggers to ensure Fault Recording data is available. The Neutral (residual) overcurrent trigger is for ground faults, phase under-voltage is for phase-phase faults.

Overcurrent trigger set at 40% or less of CT secondary rating requires a maximum of 2 amps setting for CT 5 amp secondary rating, and a maximum of a 0.4 amp setting for CT 1 amp secondary rating.

R9. Each Responsible Entity shall establish a list of monitored BES bus locations and the Elements for which Dynamic Disturbance Recording is required. The location list shall include the following: *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

9.1. A minimum of one Dynamic Disturbance Recording location per 3,000 MW of the Responsible Entity's historical peak system Load.

9.2. Generating Plants with a gross aggregate nameplate rating of 500 MVA or greater.

9.3. Locations necessary to monitor all Elements of:

- Major transmission interfaces and all permanent Flowgates and major transmission interfaces in the Eastern Interconnection
- All major transfer paths within the Western Interconnection as defined by the Regional Entity
- Major transmission interfaces in the Quebec or ERCOT Interconnections

9.4. Both ends of HVDC terminals (back-to-back or each terminal of a DC circuit) on the AC portion of the converter.

9.5. Locations necessary to monitor all Elements of Interconnection Reliability Operating Limits.

9.6 Any one Element within a major voltage sensitive area as defined by an in-service UVLS program.

Rationale for R9:

Dynamic Disturbance Recording is used for wide-area disturbance monitoring to determine the system's transient and post-transient response and validate the system model performance. Equipment is generally placed strategically based on study methodologies, including angular, frequency, voltage, and oscillation stability. However, for accurately monitoring system transient response and ensuring sufficient coverage to determine system performance, Dynamic Disturbance Recording is required at key locations in addition to a minimum requirement of DDR coverage.

Loss of large generation resources poses a frequency and angular stability risk for all Interconnections across North America. Furthermore, the dynamics of these machines during disturbances is more useful than the Sequence of Events status of the Plant because these responses help drive post-mortem analysis of large Disturbances. DDR monitoring of Generating Plants with aggregate nameplate rating of 500 MVA is required to adequately capture response provided from large Generating Plants such as nuclear, and large hydroelectric, coal, natural gas, or oil generators.

Major transmission interfaces, and their System Operating Limits (SOLs), defined by the Functional Entities provide bounds for operating and controlling the power grid in real-time. Exceeding these operating limits poses the risk of post-contingency overloading and cascading failure. Furthermore, for disturbance monitoring, these paths are used to validate the system model's response to determine if the studied conditions adequately and accurately represent real-world dynamics. DDR is required to monitor all elements of each major interface as defined by the interface's metering definition. This provides the wide-area perspective of dynamics needed for accurate analysis and recreation of system disturbances.

HVDC terminals (back-to-back or DC circuits) exchange large injections of both real and reactive power with the connected AC synchronous system. In addition, these Elements provide control capabilities and transfer large amounts of energy from one part of the system to others. For system dynamics and stability concerns, monitoring DC response and performance is necessary and therefore required.

Interconnection Reliability Operating Limits (IROLs) define operating limits within which operations must occur because they have a significant impact on an Interconnection's security and stability. These reasons drive the requirement for DDR at these locations. Sufficient DDR is required to monitor all elements of each IROL as defined by the IROL metering definition.

Voltage sensitive locations are generally well understood by Planning Coordinators and/or Reliability Coordinators. System studies identify those areas with weak reactive support, large fluctuations in voltage due to changes in reactive power injection, or areas prone to Fault-Induced Delayed Voltage Recovery (FIDVR). These locations can greatly benefit from a Dynamic Disturbance Recorder in the vicinity, possibly at the lower voltage BES Elements, to capture this phenomenon.

Each Responsible Entity (Planning Coordinator or Reliability Coordinator) is required to identify locations for DDR capability for, at a minimum, one location per 3,000 MW of historic peak load, regardless of the previously described requirements. This number of locations is included to provide adequate system-wide coverage across an Interconnection. To clarify, if any of the previously described Elements are within the Responsible Entity's area, these locations are required. If a Responsible Entity does not have a sufficient number of DDR locations to meet the one DDR per 3,000 MW of peak load requirement, additional DDR locations must be defined.

M9. Text

R10. Each Responsible Entity shall review the list established in Requirement R9 at least every five years. *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

Rationale for R10:

The list generated by the Responsible Entity shall be reviewed at least every five years to identify new Element or updates to the list based on changes to their system during this time period. The list of locations does not need to be continuously updated; however, this comprehensive list shall be maintained accurately once every five years.

M10. Text

R11. Each Responsible Entity shall establish and make available to the Transmission Owners and Generator Owners the list of Dynamic Disturbance Recording BES bus locations established in Requirement R9 and Elements for which data is to be recorded. *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

Rationale for R11:

The Responsible Entity will identify 1) the locations defined in Requirement 9, and 2) the Elements for which data is to be recorded at those locations. The list of required locations and data will be provided by the Responsible Entity to the Transmission Owners and Generator Owners who own the locations and Elements to be monitored, providing direction as necessary.

M11. Text

R12. Each Transmission Owner and Generator Owner shall have Dynamic Disturbance Recording at the BES bus locations specified by the Responsible Entity and record data on the specified Elements. *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

Rationale for R12:

Upon receipt of the monitoring requirements, the Transmission Owners and Generator Owners will provide DDR functionality at those locations and for the Elements specified based on the Implementation Plan set forth in this standard.

M12. Text

R13. Each Transmission Owner shall record electrical quantities of each Element identified by the Responsible Entity in order to determine the following Dynamic Disturbance Recording data: *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

13.1. Single phase-to-neutral or positive sequence voltages where any normal system configuration does not remove all voltage sources from service simultaneously.

13.2. The phase current on the same phase at the same voltage or positive sequence current in Requirement R13, part 13.1.

13.3. Real Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

13.4. Frequency calculated from all voltages measured at the location.

Rationale for R13:

Dynamic Disturbance Recording is used for measurement of transient response to system disturbances, which is generally 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.

There are a number of bus configurations and it is inefficient to create requirements for each configuration. However, if DDR is required at a given location, voltage must be measureable for any normal configuration of those buses at that location. For example, a breaker-and-a-half configuration may have a North Bus and South Bus, which would require that both buses have DDR voltage measurement because either can be taken out of service indefinitely. This component of the requirement is included to mitigate the potential of failed frequency, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during normal operating conditions.

If a DDR current is recorded, it should be on the same phase as the voltage measurement taken at the location. Positive sequence current can also be recorded, assuming this calculation is derived from measurement of the three phases.

For all circuits where current recording is required, real and reactive power will be recorded on a three-phase basis.

Frequency will be recorded for all voltages recorded at each location defined.

M13. Text

R14. Each Generator Owner shall record electrical quantities of each Element identified by the Responsible Entity in order to determine the following Dynamic Disturbance Recording data: *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

14.1. Any one phase-to-neutral, phase-to-phase, or positive sequence voltage at either the GSU's high side or low side voltage level.

14.2. The phase current on the same phase at the same voltage in Requirement R14, part 14.1, two phase currents for phase-to-phase voltages, or positive sequence current.

14.3. Real Power and Reactive Power (MW and MVAR) flows expressed on a three-phase basis corresponding to all circuits where current measurements are required.

14.4. Frequency calculated from all voltages measured at the location.

Rationale for R14

Each Generator Owner required to provide DDR capability as defined in this standard will provide voltage, current, real and reactive power, and frequency calculations.

Voltage records are required on the circuits connected to either the high or low side of all the generator step-up (GSU) transformers. These records can be phase-to-neutral, phase-to-phase, or positive sequence.

Current records are required on the same phase(s) if a phase-to-neutral or phase-to-phase voltage is used. Positive sequence voltage is also acceptable, assuming this calculation is derived from measurement of the three phases.

For all circuits where current recording is required, real and reactive power will be recorded on a three-phase basis.

Frequency will be recorded for all voltages recorded at each location defined.

M14. Text

R15. Each Transmission Owner and Generator Owner that is responsible for Dynamic Disturbance Recording shall have continuous recording and storage capability for the BES bus locations established in Requirement R9: *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

Exception: If the equipment was installed prior to the effective date of this standard, triggered record data lengths of at least three minutes are acceptable.

Rationale for R15:

Continuous recording and storage capability for the BES locations specified in Requirement R9 is required for all devices installed after the date specified in the Implementation Plan of this standard. The exception to this Requirement is that triggered records are acceptable if the DDR equipment, which meets the other Requirements in terms of recording and sampling, was installed prior to the effective date of this standard. Record lengths must be at least three minutes in length, and the triggering methodology must be implemented as defined in Requirement R17.

M15. Text

R16. Each Transmission Owner and Generator Owner shall have Dynamic Disturbance Recording data, for the BES bus locations and Elements specified by the Responsible Entity, conforms to the following technical specifications: *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

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

16.2. Output reporting rate of electrical quantities of at least 30 times per second.

Rationale for R16:

Input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle, is required on the input side of the DDR equipment. This ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency. This minimum input sampling requirement is also utilized in PRC-002-NPCC.

Output reporting 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 reporting speed to monitor low frequency oscillations typically of interest during power system disturbances.

M16. Text

R17. Each Transmission Owner and Generator Owner shall set each non-continuous, trigger type, Dynamic Disturbance Recording to trigger for at least one of the following (based on manufacturer's equipment capabilities): *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

- Delta Frequency trigger **TBD**
  - Eastern Interconnection
  - Western Interconnection
  - ERCOT Interconnection
  - Hydro-Quebec Interconnection
- Off nominal Frequency trigger **TBD**
- Rate of change of Frequency trigger at a minimum **TBD**
- Under-voltage set no lower than 85% of normal operating voltage for a duration of 5 seconds

Rationale for R17:

It is the intent of this requirement that each Transmission Owner and Generator Owner' shall apply at least one of these minimum triggers to ensure Dynamic Disturbance Recording data, recorded by triggerable records, is available.

M17. Text

R18. Each Transmission Owner and Generator Owner shall time synchronize all Sequence of Events Recordings, Fault Recordings, and Dynamic Disturbance Recordings for the BES bus locations established in Requirements R1 and R9 to within +/- 2 milliseconds of Coordinated Universal Time (UTC), time stamped with or without a local offset. *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

Rationale for R18:

Since the analysis of wide area events requires a large volume of records from a sizeable number of reporting sources, time synchronization is the means to provide and understand event chronology. Consequently, to ensure an accurate and consistent reconstruction of events for analysis purposes, time synchronization to a universal time source is required for the Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording, as required by the standard. Variations up to +/- 2 millisecond allow for local clock and time distribution margins of error; this is an existing requirement in PRC-018-1 R1.1. UTC is the official abbreviation for Coordinated Universal Time: an international time standard using atomic clocks for deriving and distributing precision time measurements at sub-second levels. The local time offset (expressed as a negative number) is the difference between UTC and the local time zone where the records are collected.

M18. Text

R19. Each Transmission Owner and Generator Owner shall have all Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data available, for the BES bus locations established in Requirements R1 and R9, for at least 10 calendar days after each recording. *[Violation Risk Factor: Medium] [Time Horizon: Long-term and Operations Planning]*

Rationale for R19:

This requirement defines the length of time the SOER, FR, and DDR data shall be available. Having the data available for 10 days gives entities 10 days to request the information for analysis purposes, including events analysis. If a local device can store the data for the 10 days, then it is acceptable to have it stored on that device. For equipment that cannot meet the storage requirements, a TO and GO and Responsible Entity must have a method to retrieve and store the captured data either at the local site or at a centralized collection and storage system that would be located remotely from to the site.

M19. Text

R20. Each Transmission Owner and Generator Owner shall return to service the equipment used for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording at the BES bus locations established in Requirements R1 and R9 within 90 days from the start of maintenance, upgrades, or discovery of a failure. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts and the plan for restoring the equipment to service. *[Violation Risk Factor: Lower] [Time Horizon: Long-term and Operations Planning}*

M20. Text

Rationale for R20:

Because the purpose of the standard is to ensure sufficient data is captured to analyze a wide area event, for the BES bus locations established in Requirements R1 and R9, a TO and GO must repair any failure in a reasonable time period. The drafting team selected 90-days from the start of maintenance, upgrades or discovery of a failure to account for conditions where equipment cannot be repaired on site. If the DME device will be out of service for greater than 90 days the owner shall keep record of efforts and the plan for restoring the DME to service.

R21. Each Transmission Owner and Generator Owner shall provide Sequence of Event Recording, Fault Recording, and Dynamic Disturbance Recording data, for the BES bus locations established in Requirements R1 and R9, to the Reliability Coordinator, Regional Entity, or NERC upon request: *[Violation Risk Factor: Lower] [Time Horizon: Long-term and Operations Planning]*

21.1. All Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording data shall be provided to the Reliability Coordinator, Regional Entity, or NERC within 30 calendar days of a request.

21.2. All Fault Recording and Dynamic Disturbance Recording data shall be in a format such that any software system capable of viewing and analyzing COMTRADE (IEEE Std. C37.111- 2013) files may be used to process and evaluate the data.

21.3. All data files shall be named in conformance with IEEE C37.232-2011, or its successor, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME).

Rationale for R21:

Analysis of major disturbances in the past has been significantly delayed due to lack of data and delays in receiving data from the industry. To insure data availability and timely delivery recorded data must be provided within 30 days of a request to allow timely analysis of an event to begin. Data provided in COMTRADE format will allow analysis with a single analysis tool, rather than multiple manufactures' data format specific tools. Data files named using the Recommended Practice for Naming Time Sequence Data Files will make organizing, and finding data files easier.

M21. Text

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.

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 [responsible entity] 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 [responsible entity] shall retain evidence of Requirement 1, Measure 1 for [Insert Time Period].

If a [responsible entity] is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

1.4.1 Each Transmission Owner and Generator Owner shall meet all of the following criteria when reporting Sequence of Event, Fault Recording , and Dynamic Disturbance Recording data to its Regional Entity or NERC within 30 days of a request:

- All Fault Recording and Dynamic Disturbance Recording data shall be in a format such that any software system capable of viewing and analyzing COMTRADE (IEEE Std. C37.111-1999 or successor) files may be used to process and evaluate the data,

- All data files shall be named in conformance with IEEE C37.232-2007, or its successor, Recommended Practice for Naming Time Sequence Data Files.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium				
R2	Long-term Planning	Medium				
R3	Operations & Long-term Planning	Medium				
R4	Operations & Long-term Planning	Medium				
R5	Operations & Long-term Planning	Medium				
R6	Operations & Long-term Planning	Medium				
R7	Operations & Long-term Planning	Medium				
R8	Operations & Long-term Planning	Medium				

R9	Operations & Long-term Planning	Medium				
R10	Operations & Long-term Planning	Medium				
R11	Operations & Long-term Planning	Medium				
R12	Operations & Long-term Planning	Medium				
R13	Operations & Long-term Planning	Medium				
R14	Operations & Long-term Planning	Medium				
R15	Operations & Long-term Planning	Medium				
R16	Operations & Long-term Planning	Medium				
R17	Operations & Long-term Planning	Medium				

R18	Operations & Long-term Planning	Medium				
R19	Operations & Long-term Planning	Medium				
R20	Operations & Long-term Planning	Lower				
R21	Operations & Long-term Planning	Lower				

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

PRC-002-2 ATTACHMENT 1 – SOER AND FR LOCATIONS SELECTION PROCEDURE

To establish lists of monitored BES bus locations for Sequence of Events Recording and Fault Recording required by Requirement 1 of PRC-002-2, each Transmission Owner shall follow the steps listed below:

Step 1. Determine a complete list of BES bus locations[1] that it owns.

Step 2. Reduce the list to those locations that have a maximum available calculated three phase short circuit MVA of 1500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

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

Step 4. Select the median MVA level of the 11 bus locations determined in Step 3.

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

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

a. 1500 MVA or

b. 20% of median MVA level determined in Step 5.

Step 7. <u>If there are no bus locations on the list:</u> the procedure is complete and no Fault Recording and Sequence of Events Recording will be required. Proceed to Step 9.

<u>If the list has 11 or fewer bus locations:</u> Fault Recording and Sequence of Events Recording is required at the BES bus location with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9.

<u>If the list has more than 11 bus locations:</u> Fault Recording and Sequence of Events Recording is required on at least the 10% of the BES bus locations, determined in Step 6, with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

[1] A single bus location may be considered as any bus Elements at the same voltage level within the same physical location. As an example, ring bus or breaker-and-a-half bus configurations may be considered as a single bus location.

Step 8. Fault Recording and Sequence of Events Recording is required at additional BES bus locations on the list determined in Step 6. The aggregate of the number of bus locations determined in Step 7 and this step will be at least 20% of the bus locations determined in Step 6.

The additional bus locations are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for Fault Recording and Sequence of Events Recording, therefore the following types of BES locations are recommended:

a. Electrically distant bus locations or from other DME devices.
b. Voltage sensitive areas.
c. Cohesive load and generation zones.
d. Bus locations with a relatively high number of incident transmission circuits.
e. Bus locations with reactive power devices.
f. Major facilities interconnecting outside the Transmission Owners area.

Step 9. The list of monitored locations for Sequence of Events Recording and Fault Recording for PRC-002-2 Requirement R1 is the aggregate of the bus locations determined in Step 7 and Step 8.