Unofficial Comment Form  
Project 2007-11 Disturbance Monitoring

Please **DO NOT** use this form for submitting comments. Please use the [electronic form](http://example.com) to submit comments on the Standard Authorization Request (SAR). The electronic comment form must be completed by 8 p.m. Eastern on **December 16, 2013**.

If you have questions please contact **Barb Nutter** via email or by telephone at 404-446-9692.

Click here for the [Project Page](http://example.com).

**Background Information**

Project 2007-11 Disturbance Monitoring was initiated to replace the existing fill-in-the-blank Standard PRC-002-1 Define Regional Disturbance Monitoring and Reporting Requirements with a more comprehensive standard. (Fill-in-the-blank standards are those standards that depend on regional criteria or procedures not currently contained within certain Reliability Standards, but which are needed to provide additional requirements for implementing the standards within the Regions.)

In its Order 693 (March 16, 2007) FERC did not approve or remand PRC-002-1 “...because the regional requirements for installing Disturbance Monitoring Equipment had not been submitted.” FERC, in Order 693 did approve PRC-018-1. Similar to PRC-002-1, PRC-018-1 contained Regional Reliability Organization (the term Regional Reliability Organization used in PRC-018-1, now Regional Entity) requirements. FERC stated that PRC-018-1 ensured “that disturbance monitoring equipment is installed and disturbance data is reported in accordance with comprehensive requirements.” Project 2007-11 was moved to informal development in the Fall of 2010. The Project was restored to formal development status in January, 2013.

The Purpose of PRC-002-2 is “To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.” For Sequence of Events and Fault Recording, the Drafting Team decided that it was more practical to require recording, not require equipment, to capture adequate information to analyze BES disturbances. An entity must have data recorded that could determine abnormal disturbance values at a location. It is not the “how”, but the “what” regarding data capture. The Drafting Team set up a Monitored Value Analysis Team that looked at three phase bolted bus short circuit MVA data received from members of the Drafting Teams. The Team determined that as long as data was captured for analysis from buses, the Bulk Electric System response to a disturbance could be determined. An Informal Request for Information was posted to industry from June 5, 2013 through July 5, 2013 for short circuit data from around the continent. The information received confirmed the team’s analysis. The Drafting Team developed a Locations Selection Methodology which is Attachment 1 in PRC-002-2.
For Dynamic Disturbance Recording, Requirements define the locations Dynamic Disturbance Recording data must be captured for.

The Drafting Team developed three new definitions that are used and included in the posted PRC-002-2: Dynamic Disturbance Recording (DDR), Fault Recording (FR), Sequence of Events Recording (SOER). These definitions will be added to the NERC Glossary of Terms Used in Reliability Standards.

Transmission Owners and Generator Owners will be responsible for the majority of the Requirements in PRC-002-2. Responsible Entities include Planning Coordinators and Reliability Coordinators, as applicable. Each Responsible Entity will be responsible to identify BES Elements for Dynamic Disturbance Recording.

This Project will replace PRC-002-1 with PRC-002-2, and allow the retirement of PRC-018-1.

**Transmission Owners – Please note the following:**

Requirement R1 requires each Transmission Owner to identify BES bus locations for Sequence of Events Recording (SOER) and Fault Recording (FR). The bus locations are identified using PRC-002-2 Attachment 1 – Sequence of Events Recording (SOER) and Fault Recording (FR) Locations Selection Methodology.

An Excel Workbook has been designed to assist Transmission Owners in using the methodology (referred to as the Median Method) discussed in Attachment 1. This workbook has been posted along with the other PRC-002-2 materials during this comment period to give Transmission Owners the opportunity to try out Requirement R1’s bus location method by either using their entire system data, or a selected portion of their systems to obtain a full or partial listing of the bus locations that would have to be included in for SOER and FR.

*Please use the electronic comment form to submit your final comments to NERC.*

**You do not have to answer all questions. Enter All Comments in Simple Text Format.**

Bullets, numbers, and special formatting will not be retained. Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you support the new definitions for Sequence of Events Recording, Fault Recording, and Dynamic Disturbance Recording? If not, please explain why and provide suggested changes.

☐ Yes
☒ No

Comments: The definition for SOER *optionally* includes protection devices and only mandates the monitoring of the status of Elements. This is reinforced by R3 which only dictates the recording of circuit
breaker position. The purpose of the standard is to “have adequate data available to facilitate analysis of BES disturbances”. We don’t see how any comprehensive analysis of disturbances can be done in the absence of protection device information. At least some basic protection information is integral in disturbance analysis.

We could support the definitions as used within this standard but do not support using the abbreviations SOER (or SER or SOE), FR (or DFR) and DDR as defined NERC Glossary abbreviations. These acronyms have been used by the industry for many years to label recording equipment. When industry experts and engineers refer to a FR (or a DFR) they mean the equipment, a digital fault recorder, not a particular type of recorded measurement data. Same is true for SOER (or SOE or SER) and DDR.

Since this is a data standard, strong consideration should be given to using the word “data” in place of the word “recording”, such as Dynamic Disturbance Data, Fault Data and Sequence of Events Data with acronyms of DD, FD and SD.

Also the definition of SOER presently uses the phrase “... status of Elements, which may include protection and control devices.” We recommend changing the word “Elements” to “circuit breakers” which is what is stated in R3. Also the last part of the definition referring to protection and control devices should be deleted since there is no requirement to monitor protection and control device status.

2. Do you agree with the methodology in Requirement R1 that selects the BES bus location for Sequence of Events Recording and Fault Recording? If not, please provide technical justification.

☐ Yes  ☐ No

Comments: We agree with the idea behind the methodology, however the term BES bus locations is not defined. The NERC BES definition applies to Elements, not buses. Continuing to Requirement R2, a TO might not have visibility to BES classification of elements it does not own. Planning/Reliability Coordinator would be a more applicable functional entity for this role. They should also be responsible for reaching out to the GO’s with notification for SOER and FR. A TO has no authority to perform this function; a GO might also question the bus selection and ask that another TO bus be included instead.

The methodology in Attachment 1 is overly complicated (9 steps); and following eight of these required steps, it is then left up to the T.O. to add “discretionary” stations, if desired. Just using the highest 11 station fault MVA values may not be the most accurate. Contributions from a foreign, nearby utility can raise a station’s fault values, even though the station itself is not that critical to the listing entity. Using “Station” instead of “Bus” or “Location” would be more definitive. e.g. a 230 kV “Station”, a 345 kV “Station”,...). The term “bus” can be defined in different ways, so can “location.”
3. Are the appropriate functional entities identified in the Applicability section for PRC-002-2?
   □ Yes
   □ No
   Comments:

4. Do you agree with the Elements requiring Dynamic Disturbance Recording listed in Requirement R6? If not, please provide technical justification.
   □ Yes
   □ No
   Comments: Requirement R6 is confusing. It asks for the identification of BES Elements for which Dynamic Disturbance Recording (DDR) is required but sub-Parts 6.1.1 and 6.1.2 are not criteria for “Elements”, but rather, they are criteria based on demand size and footprint. It would be helpful if the requirement is split into two: one for the threshold for having DDR (demand size and footprint, i.e., sub-Parts 6.1.1 and 6.1.2), and one for the location/element (sub-Parts 6.1.3 to 6.1.6). Suggest moving the minimum quantities in sub-Parts 6.1.1 (minimum 1 DDR per 3000 MW) and 6.1.2 (minimum 1 DDR per RE footprint) to the end of the list. In that way the requirements for sub-Parts 6.1.3 (Generation resources), 6.1.4 (Flowgates, etc…), 6.1.5 (HVDC), 6.1.6 (IROLs) and 6.1.7 (UVLS) will be stated up front as non-negotiable requirements, and state that additional DDR locations are only needed if fulfilling the first 5 do not meet the two extra minimum quantities requirements.

Sub-Part 6.1.3--Needs to be clarified to make it understood how to add up the MW ratings of combined cycle unit generators and cross compound generators. Some examples would be helpful.

Sub-Part 6.1.4, first bullet – Requiring monitoring of all “Flowgates” on the Eastern Interconnection seems arbitrary and diminishes the role of those with the best understanding of the nature of their system to determine the appropriate locations for DDRs. If “Flowgate” monitoring is required, this item should include a link to the official list of NERC Flowgates so that the “Responsible Entity” knows where they need to install DDRs. For example, the NY-NE interface is one of the official NERC Flowgates, which means that entities will need a DDR at each of eight stations that interconnect with New York; while entities on the other end of the interconnection in NE will need to do the same. Regarding “monitor all Elements of: all permanent Flowgates”. If a Flowgate is made up of a combination of several transmission lines and transformers, does every line need to be monitored? Do both ends of the lines need to be monitored? Does every transformer need to be monitored (low side or high side side)? Please show some typical examples. The guideline for R6 included in the draft fails to explain why all Flowgates should be monitored. The Book of Flowgates includes circuits that can become thermally overloaded under outage conditions at low flows, e.g. circuits with the maximum pre-contingency flow of 150 MW at unity power factor. This requirement seems to be very conservative and somehow conflicting with sub-Part 6.1.3.2
because there are many generation plants that do not exceed the specified thresholds by a small number and those generating plants are not monitored. Clarify that DDR is for “all permanent Flowgates” ONLY if the Flowgates are BES Elements.

Sub-Part 6.1.5 – this will require the installation of DDRs at HVDC facilities that are smaller than the generator requirement listed in sub-Part 6.1.3 (500 MW). This requirement should be rephrased to deal with the cases when the ends of high-voltage direct current (HVDC) terminals (back-to-back or each terminal of a DC circuit) on the alternating current (AC) portion of the converter are owned by different entities.

Sub-Part 6.1.6 – This requirement could lead to installation of DDRs at many substations to just capture one flow that is part of an IROL. Also, DDR data is of little value for IROLS that are thermal in nature.

Sub-Part 6.1.6/Guideline - The Guideline for R6 included in the draft has no explanation about why all Elements associated with Interconnection Reliability Operating Limits (IROLS) should be monitored. The NERC lists including all elements associated with IROLS are very extensive. This requirement will dramatically increase the number of the DDRs need to be installed. This could cause too excessive burden on some TOs. Also, there is nothing to limit the burden which can be placed on the TO by a Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable). Depending on the impact, a 3-year implementation plan might not be achievable.

5. Do you agree with the VRFs/VSLs and the Drafting Team’s justification? If not, please explain why.
   - Yes
   - No
   Comments: The VSLs don’t take into account the size of responsible entity. Larger entities should be given more time.

6. Do you agree with the Implementation Plan? If not, please explain why.
   - Yes
   - No
   Comments: Recommend updating the “entity” for the following requirements on the Implementation Plan Summary:
   - R8 - TO
   - R9 - GO
   - R10 - TO/GO

The Implementation Plan doesn’t take into account the size of responsible entity. Larger entities should be given more time (see response to Question 5).
7. If you have any other comments that you haven’t already mentioned above, please provide them here:

Comments: Regarding Attachment 1:

a) The term "BES bus location" is not clear. There could be two or more BES bus locations at the same physical location (substation). The definition of "BES bus" could not be found.

b) Step 7 of Attachment 1 does not specify how to round the 10% of the BES bus locations, determined in Step 6, with the highest maximum available calculated three phase short circuit MVA.

c) Step 8 of Attachment 1 does not specify how to round the additional 10% of the BES bus locations determined in Step 6.

d) Attachment 1 does not specify how to distribute an odd number for 20% of the BES bus locations between b) and c) from above.

In Part 1.2 and Part 6.2, what prevents a TO or RE from assessing the locations and elements too frequently? As written, it provides no clause to prevent excessively short re-assessment periods. There should be some minimum time (say several years) between assessments to provide stability where monitoring is really needed. Frequent assessments could move locations above and below the minimum criteria line and create confusion.

We agree with R1, but do not see the need for R2 because through R1 and Attachment 1 each TO has already identified the bus locations that it owns for having Sequence of Events Recording (SOER) and Fault Recording (FR). There is not another owner(s) that a TO needs to communicate the list to, unless the “list of BES bus locations that it owns” stated in Step 1 of Attachment 1 means only the location ownership but not the Element ownership. But if that’s the case, Step 1 in Attachment 1 needs to be clarified.

In R2, it infers that the TO as part of R1 developed a list of Elements, however R1 requires the TO only to determine BES bus locations. If it was the intent that the TO determine the specific Elements, we suggest R2 be reworded to say “Each transmission owner shall identify BES Elements at the bus locations established in Requirement R1 and shall notify...”. If it was the intent that the GOs (and other affected TOs) to determine which BES Elements they own at the bus locations, then do not require that the TO identify the BES Elements, instead let the owners of those Elements identify their Elements.

The intent of Requirement R2 is for Transmission Owners to notify “other” owners of BES Elements, as explained in the Rationale statement. The requirement as written would also require the Transmission Owner to notify itself. Therefore, suggest revising R2 and M2 as follows:

R2. Each Transmission Owner that identifies BES Elements at the locations established in Requirement R1 shall notify the “other” owners of those Elements...
M2. The Transmission Owner has dated evidence (electronic or hardcopy) of notification to “other” owners of Elements...

Requirement R3 specifically asks to have SOER, however the guideline for R3 allows for the breaker status to be determined by analysis of suitably time synchronized FRs with the data provided in the manner detailed in R4. This should be identified in the Requirement itself. The guideline is a non-binding portion of a standard.

The guideline for R3 has a typo (it should reference R4 instead of R14).

Requirement R4 is not clear if determine means that the required BES Elements of TO and GO shall have waveforms for each phase current and the residual or neutral current.

Regarding Requirement R4, Part 4.2, it is not clear if only high-side voltage winding voltages and currents need to be recorded. Clarification is needed if low-side voltage windings and transformer neutral need to be monitored also.

Part 4.1- More specificity is needed in the requirement. Are phase to neutral voltages needed for each line? If common bus side voltages are available is it sufficient to have one set of phase-neutral voltages for the bus location? If so the wording should more accurately reflect this. Presently it reads – “.... Voltages for each phase of either each line or bus.” which could be confusing.

Part 4.2 – Residual current and neutral current are two different quantities. Residual current is current present in the neutral of the Element CT circuit while neutral current implies current directly measured by a CT in the neutral of an Element. This wording should probably be more specific by stating if the monitored transformer has a neutral CT it should be monitored (if this was the intention of the Drafting Team).

Sub-Part 4.2.1 – Is monitoring required on both HV and LV sides of these transformers? The wording for this requirement should be more specific.

M4 (1): add “plus evidence the device was commissioned at the specific bus in question”.

In Part 5.1, change wording (similar to how R10.2 is stated) to indicate that meeting either one of the bullets satisfies the requirement. We suggest R5.1 be reworded to say “A single record or multiple records that include at least one of the following.”

Part 5.1 – the two bullet items in this requirement are confusing and should be reworded to clarify what is intended.
Part 5.1 Bullet 2- The wording should be changed as follows: “At least two cycles of the pre-trigger data, the first three cycles of the fault as seen by the Fault Recorder, and the final cycle of the fault as seen by the Fault Recorder.” Because the deployment of Fault Recorders are not required on every BES bus, unless the fault is being cleared on an Element directly connected to the bus, the fault recorder may not always accurately capture the fault information if it is occurring more than one bus away from the Fault Recorder location. Without this additional wording the Fault Recorder would have to capture the actual final cycle of the fault which may be impossible if it is not directly monitoring it.

Part 5.2 assumes that SOE recording is driven by DFR analog sampling since it infers the achievement of a 1ms digital event resolution for a 960Hz (16x60Hz) analog sample rate. Stating analog and event resolution requirements (i.e. 16 samples per cycle and 1ms event resolution respectively) separately and explicitly is clearer and accommodates instances where SOER is separate from analog sampling.

Part 5.3.1. asks to have trigger settings for neutral (residual) overcurrent, which implies for R4 that it is necessary not only to determine but to monitor either each phase current or neutral current.

Regarding requirement R6, the standard should not create a new term like “Responsible Entity” but should only refer to specific NERC entities like TO, GO, RC, etc.

If the Drafting Team decides to retain sub-Part 6.1.6, then it is recommended the phrase "all Elements associated with Interconnection Reliability Operating Limits" be replaced with "elements critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" similar to the language used in CIP-002-4.

CIP-002-4 - Attachment 1 Critical Asset Criteria reads:

1.8. Transmission Facilities at a single station or substation location that are identified by the Reliability Coordinator, Planning Authority or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
There is an error in the mapping document. R6 of PRC-018-1 speaks to the need for maintenance of DME. The Drafting Team has mapped this requirement to R14 of PRC-002-2. These two activities are not the same since R14 is a break-fix requirement for DME, while R6 of PRC-018 speaks to maintenance activities of DME. Maintenance of DME ensures devices that need calibration are calibrated as well as correcting any non-annunciated failures. R14 of PRC-002-2 requires entities to repair equipment that they know is in a failed state.

The Part 8.3 wording is too restrictive. Real and reactive power may not be able to be determined operationally if say a bus is split at the time of an event (or the split is caused by an event). Suggest the Drafting Team correct this requirement by referencing “nominal” real and reactive power which refers to the original design of the DDR channel assignments which under normal operating conditions Real and Reactive Power could be determined. The design should be assuming all normally-closed circuit breakers on a bus are closed. This avoids being out of compliance during a specific event, if open bus breakers preclude recording the MVA flows on all elements.

Requirement R10 should allow the legacy equipment to have multiple triggered records which make up the required length. It is stated that triggered records from existing equipment can be accepted in lieu of continuous recording if the triggered records meet the criteria in 10.1 and 10.2. If continuous recording is available and meet all criteria, are triggered DDR records required?

R13 – this requirement places the RC, RE and/or NERC in the middle of data sharing. There is no requirement in the standard to facilitate entities to partake in data sharing. Is this really the intent? What if adjacent entities need to exchange post-disturbance information? Does that really need to occur via the RC, RE or NERC if an entity cannot directly request necessary data?

Requirement R13, Part 13.3. asks for SOER data in Comma Separated Value (.CSV) format whereas the majority of Disturbance Monitoring Equipment (DME) do not save data in this format. In addition, if breaker open/close position determination from FR data is acceptable, no .CSV file can be created by the recording tool itself. There is no need to require this data to be written in CSV format. Tab delimited text would work as well and would not limit the use of commas in descriptors or other entries. The format described in Attachment 2 is limiting and incomplete (see comments on Attachment 2 below).

Similarly, R13 Part 13.4. asks for FR and DDR data in C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), formatted files whereas the majority of DME equipment does not save data in this format. Are manually converted records acceptable? This requires that Fault Recording and Disturbance Recording data will be provided in COMTRADE (C37.111) formatted files, but does not specify a revision level or year for the COMTRADE standard. The requirement should specify “C37.111-
2013 or later” in order to require a version of COMTRADE that includes formatting for phasor data for Disturbance Recording. Prior versions of C37.111 were not compatible with phasor data.

In R14, reword to indicate that the second bullet is only applicable if the first bullet is not completed within 90 days. We suggest this wording for the second bullet – “If recording ability is not restored within 90 days, report the inability…”

The Rationale for requirement R14 recognizes that the DME equipment cannot be always returned to service within 90 calendar days of the discovery of a failure. Requirement R14 itself, however, is not clear and should be rewritten to reflect that.

PRC-002-2 and the associated Implementation Plan do not address coordination with existing mandatory Regional Reliability Standards, specifically, PRC-002-NPCC-01, Disturbance Monitoring. As of October 20, 2013, NPCC applicable entities are two years into a four year FERC approved Implementation Plan. NPCC applicable entities have no option but to continue to implement the Regional Reliability Standard or be found non-compliant with this Regional Reliability Standard. The development of a continent-wide NERC Reliability Standard creates uncertainty for NPCC applicable entities regarding the adequacy of the NPCC Disturbance Monitoring Equipment (DME) installed to date and the potential for additional DME locations and/or requirements.

Regarding Attachment 2, the format in Attachment 2 is limited and incomplete. While the information required is obviously necessary, the format limits or omits information available from some SOERs. R13.3 states that the files must be comma-delimited, but Attachment 2 makes no statement about the length of any string or value. There is no provision for SOERs which may have detailed descriptors of the contacts being monitored but may be a single string. “Local Time Offset from UTC” should be expressed in hours before or after UTC rather than by letter designations. There is no provision for acceptable terms for “State” except for “OPEN” “and “CLOSE”. Other terms may be more appropriate for some devices monitored by an SOER, such as “ENABLED” or “DISABLED”, “ON” or “OFF”, etc. In short, Attachment 2 appears to be an attempt at defining a standard but does not adequately define a format. Development of such a standard may be better left to an IEEE Working Group or other entity.