Individual or group. (67 Responses)
Name (45 Responses)
Organization (45 Responses)
Group Name (22 Responses)
Lead Contact (22 Responses)
Question 1 (52 Responses)
Question 1 Comments (61 Responses)
Question 2 (55 Responses)
Question 2 Comments (61 Responses)
Question 3 (0 Responses)
Question 3 Comments (61 Responses)

Individual
David Jendras
Ameren
No
(1) In addition to our comments we adopt the SERC PCS comments, and include them by reference. (2) As we have stated in our previous comments, we have installed over 30 PMUs on our system over the last 3 years in conjunction with our Planning Coordinator. This required significant effort and resources to perform this installation work. Even though they have not yet been needed for disturbance analysis, some operating visualization tools are being used and we have reviewed some minor perturbations. We respectfully disagree with the drafting team's brief justification in the Rationale for R5. We still believe the resultant number of PMUs which might be needed under the new standard would be burdensome to most entities. (3) Our software vendor has made known to us that they do not presently have the full capability as described in Requirement 11 implemented in our data concentrator software.
Group
Dominion
Mike Garton
Yes
Yes
As stated in Dominion's previous comments: "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. Dominion cannot support this continent-wide standard without inclusion of a variance for the NPCC Region (PRC-002-NPCC-01)." The standard drafting team (SDT) in response provided: "The DMSDT is aware that the NPCC DMSDT has been reconvened to review the Regional Standard with respect to PRC-002-2 after it is approved." While Dominion appreciates the SDT response, the fact remains that NPCC applicable entities continue to implement the FERC approved NPCC Regional Reliability Standard that could result in over/under installing DM capability when compared to PRC-002-2, once approved. Therefore, Dominion again urges the SDT to include a Variance in PRC-002-2 that excludes entities subject to PRC-002-NPCC-01 from the applicability section of this standard.
Group
Northeast Power Coordinating Council

Guy Zito
Yes
The term BES bus is not a defined term, it is only described in Step 1 of Attachment 1. Note that NERC's Definition of Bulk Electric System (Phase 2) definition applies to Elements. Requirement R3, sub-Part 3.1 requires to have "Phase-to-neutral voltages for each phase of each specified BES bus". Since BES buses, as described in Attachment 1, may not represent physical buses, this sub-Part is not clear. For example, a breaker-and-a-half design with two physical buses. A Transmission Owner (TO) might not have visibility of the BES classification of Elements it does not own. It is recommended that the TO provide the list of identified BES buses to their PC / RC. The PC/RC will review the received list from the TO, and determine if the list contains BES Elements owned by others, and notify those owners whose BES Elements may require sequence of events recording (SER) and/or fault recording (FR) data. Reference to (undefined) BES buses in Requirement R5 makes this requirement open to interpretations. Sub-Part 5.1.2 requires the inclusion of "Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity", and its bullets include stability related interfaces or other significant Flowgates, Elements associated with Interconnection Reliability Operating Limits (IROLs), and voltage stability limited transfer paths or load serving areas. The different Parts and sub-Parts of R5 could require a large number of DDRs for TOs which have Flowgates, IROLs, and /or UVLS schemes. The number of required DDRs could become significantly larger than the minimum set of one BES Element plus one additional BES Element for each additional 3,000 MW of load, which could cause excessive burden on some TOs. It is also suggested to eliminate the potential overlap of sub-Parts 5.1.2, 5.1.4, and 5.1.5 by consolidating sub-Parts. Finally, it is recommended that "One or more BES Elements associated with Interconnection Reliability Operating Limits (IROLs)" in sub-Part 5.1.4 be replaced with "Any one BES Element critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies" to be consistent with the language in CIP-002-5.1. Sub-Part 5.1.4 requires clarification. The Drafting Team should consider shortening R1 by listing Parts.
Yes
There should be consistency between Parts 5.1.2, 5.1.4, and 5.1.5. The Drafting Team in 5.1.2 and 5.1.5 require DDR on ANY ONE BES Element but in 5.1.4 it uses "One or more BES Elements…". Reading the DT response to the last comment round it seems the intent was to be consistent for these three items; only one BES is required to be monitored. If true then standardize on ANY ONE BES element. Refer to the comments in Question 1.
An additional implementation requirement or effective date should be included to address the situation when after the 5 year evaluation an additional element is identified for FR or DDR to afford the TO or GO to budget and install additional equipment. The draft PRC-005-X standard included language to address this in its latest draft. Consider adding to the technical guidelines for R6 more information surrounding the allowance for the use of a common bus voltage measurement where appropriate to monitor multiple BES Elements. Suggest adding to the second paragraph in the guideline for R6: The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the Standard is not to require measurement of each BES Element where a common bus measurement is available. Where a common measurement is utilized the Owner must plan the installation such that a bus outage would not result in the DDR data to be compromised. For example,…etc….. Part 11.4 requires the use of C37.111-2013. This could be an issue if an Entity has not upgraded its equipment of firmware. In R8 an exception is allowed for DDR owners with older equipment. A similar tack should be applied here. The Standard should not force replacement. Attachment 1 does not specify how to distribute an odd number for 20% of the BES buses between 10% of the BES buses and additional 10% of the BES buses (both determined in Step 6), e.g. if twenty-one (21) buses in total are required. Requirement R8 should allow legacy equipment to have multiple triggered records which when combined into one time synchronized record make up the required length of three minutes. Requirement R11, Part 11.3 requires SER data in Comma Separated Value (.CSV) format following Attachment 2 whereas the majority of Disturbance Monitoring Equipment (DME) does not save data in this format. Can the Drafting Team provide a name of DME which gives the data in this format? Requirement R11, Part 11.4 requires FR and DDR data in C37.111 (C37.111-2013 or later) 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? Requirement R11, Part 11.5 requires data files

to be named in conformance with C37.232 IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME) whereas the majority of DME equipment does not save data in this format.
Individual
Leonard Kula
Independent Electricity System Operator
No
We agree with the merging of R2 into R1, but not the revised R5 which combined R6 and R7. Please see our comments under Q2, below.
No
(a) R5 is unclear as it mixes BES Buses with BES Elements. If the responsible entity (a PC or an RC) is to identify BES Elements for which dynamic disturbance recording (DDR) data is required, then it needs to notify ALL such Elements' owners, and there is no need to mention "of BES Elements connected to those BES buses". However, if the requirement is intended to ask the responsible entity to identify BES buses for which dynamic disturbance recording (DDR) data is required, then it needs to notify the owners of the BES buses AND the owners of the BES Elements connected to these BES buses. We suggest the SDT to review the intent of the requirement, and revise it to clearly convey the requirements on what is it the responsible entity needs to identify, and to whom it needs to notify. (b) Part 5.1.2: The term "significant Flowgates" is subject to interpretation since it is not clear what "significant" really means. We suggest the SDT to clarify this term or provide more specificity. (c) Part 5.1.4: It is not clear whether or not the BES Element associated with an IROL is the monitored element or the contingent element or both. This needs to be clarified. (d) Part 5.2: This part requires adding one BES Element for each additional 3,000 MW of an entity's historical peak system Demand, but the word "its" is unclear whether it means the responsible entity (in this case the PC or RC) or the BA. We suggest to reword it to clearly convey that it is the responsible entity's area historical peak system Demand. Note that additional clarity may be needed if the "its" refers to a PC or RC area since within a PC or RC area, there may be multiple BAs and TOPs within which their system peak demand could occur at different times. Thus, Part 5.2 needs to clearly convey whether it is the total non-simultaneous peak demands of all BAs within an area, or it is the one-of highest demand of the entire area
Group
Peak Reliability
Jared Shakespeare
No
The initial list of locations should come from the owners (TOs and GOs) with a subsequent review process as identified by the Responsible Entity. The Responsible Entity should have the authority to require additions as it sees necessary. Owners should provide the initial list because they have access to the information and would bear the cost of installing DDRs.
No
The reference to the WECC Path Rating Catalog should be removed because the remaining bullet points cover everything in the Path Rating Catalog. The WECC Path Rating Catalog can be changed without going through any Standard development process. Changes to the Path Rating Catalog changes Requirement impact.
Applicability section: the Responsible Entity in all Interconnections should be the Planning Coordinator or Reliability Coordinator. R5.1.2, bullet 1, the term "significant Flowgates" appears to be undefined. Does it need to be clarified? R8: undervoltage trigger set no lower than 85% of normal operating voltage – what is normal operating voltage? For a 500 kV sysem, is it 500 kV or is it the average bus voltage for a specified period of time (such as 525kV)?
Individual
Jo-Anne Ross
Manitoba Hydro
Yes

Yes
1. Implementation Plan- The first paragraph simply describes a date that is synonymous with the Effective Date of the Standard. Accordingly, Manitoba Hydro recommends that this paragraph be abbreviated and made consistent with the third paragraph, by stating that:" Entities shall be 100% compliant on the Effective Date." 2. Similarly, the second paragraph under Implementation Plan describes a date that is three months after the Effective Date of the standard. Manitoba Hydro recommends that the wording be revised to state that:"Entities shall be 100% compliant within three months after the Effective Date. 3. R1 requires transmission Owners to notify other owners that certain BES Elements may require SER/ FR data within 90 days, however it does not specify when the 90 day period runs from. This could be interpreted as running from the Effective Date of the standard or from the day that the BES Element is identified(which could be prior to the Effective Date given that entities must be compliant with applying the methodology and identifying BES busses for which data is required as of the Effective date) . Manitoba Hydro therefore recommends that the ninety day period be clarified. 4. R5-(i) For the same reasons stated above, Manitoba Hydro recommends that the ninety day period be clarified. (ii) The contents of the notice to other owners (i.e. that certain BES elements "may" require data) conflicts with R7 which "requires" that an owner who has been notified to determine certain electrical quantities. Therefore, Manitoba Hydro recommends that the "may" in R5 be deleted.
Individual
Tracy Richardson
Springfield Utility Board
• Requirement 4, specifically 4.1, requires a single record or multiple records that include "a pre-trigger 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." This 32-total cycle creates a limit on SUB's ability to store event reports, and we assume is does for many others, as well. Much of the commonly used and standard software, including that used by Springfield Utility Board, utilizes a 30-cycle event report (2 cycles pre-fault and 28 cycles post-trigger. It does not seem unreasonable to change the language from 32 cycles to 30, so that entities will not incur the unnecessary expense of either purchasing new software or developing a work-around with their current software. • The "buses" language in Attachment 1, Step 7 should be clarified. SUB believes it should read "bus" and not "buses".
Individual
John Allen
City Utilities of Springfield, MO
No
We support the merging of R2 into R1 and R7 into new R5. However, we do not support R1 Attachment 1 methodology regarding identifying BES buses for locating SER & FR devices to capture SER & FR data. See comments in question #3 for our reasoning.
No
The R5 language is confusing to me. It appears the Responsible Entity is charged with identifying Elements (not buses), but then the requirement language shifts to notifying owners of Elements connected to "those BES buses" and later reevaluating "identified buses". How are the buses "identified"? Is this an oversight based on the changes made to the earlier version of the Standard? Please clarify.
We continue to believe the Attachment 1 fault MVA threshold established in R1 to identify potential buses from which to pick locations for FR (and SER) data is too low. To provide a context for our comment, our system has a peak load of 800 MW serving approximately 110,000 customers in a service territory covering 320 square miles (less than one county) with local generating capacity of 1100 MW. This is a very compact system containing a relatively small geographic footprint with 17 BES buses as defined within this draft standard. All of these 17 BES buses have fault MVA above the 1500 MVA threshold, ranging from 8,000 MVA down to 2,900 MVA with a median value (bus 6 out of the top 11) of 5,800 MVA. The top 10 BES buses on our system all have a fault MVA above 5,000.

This PRC-002-2 draft Standard will require us to have FR data for 4 buses (20%) overall. The top 2 BES buses (10%) where FR data would be required will be electrically less than 2 miles apart. The other 2 buses (additional 10%) would be located 25 miles or less electrically from the first 2 buses regardless of how we elected to determine these locations. All this data will be electrically concentrated in a small geographical area, which doesn't appear to lead to a wide-area view of the overall BES. Additionally, several of the above mentioned buses have only two (2) BES sources (Distribution buses with only 2 transmission lines connected) or tapped buses with Distribution transformer(s) and no transmission breakers. Are these buses really important to the BES in the context of DME data? It seems the PRC-002-2 R1 Attachment 1 method only serves to unnecessarily inflate the number of BES buses on which the overall percentage of required locations will be calculated. We recognize the difficulty the SDT had in determining the appropriate coverage for FR data, but contend that a fault MVA threshold closer to 4500 MVA and an overall coverage percentage of 10% is adequate. This would still result in our system having FR data at 2 buses which could be electrically separated by approximately 25 miles. Additionally, we believe buses with only limited sources from the BES should be excluded out-of-hand by some other "test" mechanism within the Attachment 1 document or some other vehicle. Regarding R3: 1) Is it the intent of the Standard that FR data is to be determined for all currents defined on all Elements connected to a selected bus for any single fault on any Element connected to the bus? (i.e. if using digital relays for FR, do relays on each element (line or transformer) need to trigger for faults on any element connected to that bus?) 2) What are the expectations for faults and/or disturbances located remotely from the selected bus – how sensitive are they expected to be? In reality, are these FR devices expected to be a lower level disturbance recorder? 3) If data is expected to be available for conditions other than just faults, the data should not be classified as Fault Recording data or at least further definition/clarification should be provided. 4) Some of the discussion in the rationale box for R3 seems to suggest the FR data be used for fault analysis, as it applies to determining correct and incorrect breaker operations – Misoperation determination. In the case of installed modern microprocessor relays, the protective relay(s) should be able to determine the nature of the fault, the elements that operated, fault location, voltages and currents and many other particulars associated with a fault. Generally, FR is an unnecessary addition of equipment in these situations from the perspective of fault analysis to determine the correctness of protection system operation. Regarding R4: We propose changing the 30 cycle post trigger record length in the first bullet under R4.1 to a total record length of 30 cycles. The current wording requires a 32 cycle minimum total record length. We believe the 30 cycle total record length better matches existing microprocessor relay functionality for those that may wish to employ them in this fashion.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
ATC asks that the SDT consider the following recommended changes to add clarity to the subrequirements: R5.1.2, bullet 1 – Add "as judged by the Responsible Entities," to end of statement. R5.1.2, bullet 4 – Add "(not local Balancing Authorities)" after "Balancing Authority." R5.1.2, bullet 5 – Add "as judged by the Responsible Entities," to end of statement. R5.2.2 – Add "within the past 10 years" to the end of statement for time clarity.
Individual
Barbara Kedrowski
Wisconsin Electric Power Co
Yes
Yes
• R1: We suggest that the intent should be that the buses selected according to Attachment 1 will only be those that operate at or above 100 kv ? We believe that this should be specified in

Attachment 1. • R2: The Measure M2, Part (1), should be changed to “documents describing the device interconnections and configurations which MAY include a single design standard as representative for common installations… “. This will provide greater clarity that a single design standard is sufficient for evidence, but that it is not required. • R2, Measure M2: In addition, as acceptable evidence, the list in M2 should also include “station drawings” as allowed in M10. • R3: The Measure M3, Part (1), should be changed to “documents describing the device specifications and configurations which may include a single design standard as representative for common installations;”, similar to the wording in R2. As written, the Measure would require entities to have a “single design standard”, which is not part of the standard Requirements. In addition, a new Part (3) should be added to allow “station drawings” as permissible evidence • R3 and R4: The Generator Owner is listed here, but it is not clear what requirements apply to it, if it does not own any equipment listed in 3.1 or 3.2. In light of the SDT’s statements about the superiority of dynamic disturbance recording for generators, we strongly urge that the applicability of R3 and R4 for Generator Owners be removed. • R4: The Measure M4, Part (1), should be changed to: “(1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3)”… • R7: “Each Generator Owner shall have DDR data for each BES Element it owns and is notified according to Requirement R5, to determine the following electrical quantities…” This wording is not clear. We suggest using wording, similar to R6, “Each Generator Owner shall have DDR data for each BES Element it owns for which it received notification as identified in Requirement R5, to determine the following electrical quantities…” • R7: In Measure 7, Part (1), we suggest changing to : “(1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations;” This will allow needed flexibility in providing reasonable evidence. • R8: In Measure 8, make the same change as described above in M7. • R9: The Measure 9, Part (1), should be changed to: “(1) documents describing the device specification, configuration, or settings”. • R10: The Measure 10, Part (1), should be changed to: “(1) documents describing the device specification, configuration, or settings”. • Guidelines and Technical Basis Section , Guideline for Requirement R2, two statements are made that are at least unclear, if not contradictory: “SER data for generator breaker operations provides little useful data of generator loading.” “Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers connected to the Transmission Owner’s bus”. Please clarify or revise as necessary.
Individual
David Thorne
Pepco Holdings Inc.
Yes
Yes
Under requirement R11.2, suggest modifying the wording to the following: The recorded data will be retained for a minimum of 10 calendar days.
Individual
Thomas Foltz
American Electric Power
No
R1: The scope for the process in Attachment 1 should be limited to only those BES buses that have local protection systems that serve to protect the connected BES elements. R1: The process for identifying BES buses within Attachment 1 could lead to a breaker protected load bus, with only two BES source lines, being in the “top 10%” of locations that must have DFR/SER. The reason for such a location being in the top 10% would be driven by its proximity to other top 10% BES buses. The Standard should allow for exclusion of such locations, provided they are substituted by the next BES bus in the list. AEP believes this change would allow DFR/SER equipment to be deployed where proper event analysis is truly needed. An alternate approach would be to completely eliminate the top 10% criteria, which would allow industry maximum flexibility in determining the most appropriate location for such installations. R1 & R5: As written, these requirements are single sentences which are five lines in length. With no transitions of thought, they are difficult to read. The

wording should be revised to break up independent thoughts so it reads more concisely. R1 & R5: The notification within 90 calendar days has no reference point. The requirements should be revised to state "... within 90 days of completing the Attachment 1 methodology" or similar wording. R1 & R5: Both requirements state "BES Elements may require..." Why is this a "may" statement? This seems to be in conflict with the beginning statement of the requirement that indicates a bright line identification of what requires monitoring. AEP recommends employing a consistent structure for R1 and R5. The criteria for R1 are contained within an appendix, while the criteria for R5 are contained within the requirement. AEP recommends modifying R1 so that the notified entity has the option to monitor either the local or the remote terminal of the subject Element.
No
While AEP has no disagreement with the Elements as specified in R5.1, the standard lacks clarity in what flexibility if any, the Responsible Entity has in selecting them. For example, the text "may require DDR data" implies some flexibility in that regard, and such flexibility should be made more explicit within the standard. It would be more clear if the minimums provided in 5.2 were provided *before* the Elements specified in 5.1 (essentially a swap of 5.1 and 5.2).
AEP believes that the wording of requirement R11.2 clearly conveys the drafting team's intent that an entity is not required to retain more than 10 days of disturbance monitoring data at any point in time. Unfortunately, this intent is blurred by the Compliance Evidence Retention's opening paragraph and the statement that "The Transmission Owner and Generator Owner shall retain evidence of Requirements R2, R3, R4, R8, R9, R10, R11, and R12... for three calendar years." The Evidence Retention, as written, could be interpreted as requiring an entity to maintain three or more years' worth of SER, FR and DDR data. The issue is further confused by the proposed PRC-002-2 RSAW in which the Evidence Requested and the Compliance Assessment Approach for R2, R3, R4, R8, R9, R10 and R11 indicate that SER, FR and DDR data is required to demonstrate compliance and imply that an entity is required to keep all SER, FR and DDR data within the audit window. AEP believes that retaining years of disturbance monitoring data is overly burdensome, provides little to no benefit to reliability and is not the intent of the drafting team. The standard should be revised to align the Compliance Evidence Retention with the Requirements and to more clearly convey the 10 day data retention requirement. The Implementation Plan includes the following "Entities shall be 100% compliant with a reassessed list from Requirement R1 or R5 within three (3) years following notification of the list." We agree with this statement, but believe it would be more appropriate to include it within the Standard itself, rather than only within the Implementation. R1: The SDT should clarify who takes the lead role to notify other owners when there are multiple owners of a bus. Presumably it would be the company identified as the owner in the fault model being used but this should be clarified. Also, notification alone should not be sufficient in identifying monitored buses. There should be agreement from all owners that a bus should be monitored before it is included in the monitored list, unless it is in the top 10% which indicates it *must* be monitored. R2: It is unclear from the wording of R2 whether the TO/GO must monitor all circuit breakers connected to an identified bus or only circuit breakers connected to the identified bus that are associated with a BES Element. For example, would a 138 kV circuit breaker for a radial fed station service transformer be required to be monitored if it is connected to a selected bus? In this case, the station service transformer would not be a BES Element. We do not believe it would be appropriate to require SER or DFR data in this scenario, but the standard does not explicitly prevent such an interpretation. We suggest making it clear that the element is *both* connected directly to the BES buses identified in Requirement R1 *and* associated with the BES Elements at those BES buses identified in Requirement R1. R3: The Application Guide implies that GSU leads are not considered lines for this standard. The requirement should be revised to clearly indicate this. Similarly, station service or reserve transformers should likewise be explicitly excluded. R3: The callout for R3 states "The required electrical quantities may either be directly measured or derivable if sufficient FR data is captured". The allowance for derivable methods is specified only in the callout, and is not explicit within the standard itself. This allowance needs to remain somewhere in the standard. Guideline for Requirement R3: We are confused by the exclusion "For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator in case of fault on the transmission system will be captured by FR data on the transmission system." We do not understand how the generation currents could be calculated from the transmission currents for faults on the interconnection. In addition, is it the drafting team's intent to exclude most generating units from fault recording? R12:

We see no reliability benefit in sending all CAP's to the Regional Entity, and recommend revising it in consideration of Paragraph 81. Rather, it should be acceptable to only require the TO/GO to develop and execute a CAP and to make this information available to the RE within 30 calendar days of a request. AEP recommends revising the purpose statement to read "To ensure adequate data is available to NERC to facilitate event analysis of major BES disturbances. AEP recommends establishing only 5 requirements. There should be a requirement for each of the main objectives (establish a data set for FR/SER, establish a data set for DDR, provide FR/SER data upon request, provide DDR data upon request), and a single requirement for repair. AEP recommends modifying R1 so that the notified entity has the option to monitor either the local or the remote terminal of the subject Element. AEP recommends modifying R2-R4 and R6-R11 to clearly exempt data lost due to an equipment failure properly identified per R12. AEP recommends modifying R3 so that only 3 of the 4 currents are required to be recorded. Since the fourth current can be calculated by the other three, there is no reliability impact for recording only three currents.
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
Yes
No
See comments under Question 3
The three-phase short circuit level minimum of 1500 MVA at BES voltage levels is low. As a result, entities must sort through large numbers of buses when only the top 11 would need to be selected. Buses at low three-phase fault current are not typically conducive to disturbance monitoring equipment. For example, a 345 kV bus that carries 3000 amps (normal flow) would be a candidate for PRC-002 even without applying a three-phase fault. It would seem that a threshold of 10,000 MVA is technically justifiable, since most BES stations that have over 10,000 MVA of available three-phase fault current are candidates for being critical facilities that would benefit from disturbance monitoring equipment or already have such equipment installed. This would also reduce the number of buses that the TO needs to review. There is uncertainty regarding the technical justification for the "11" BES buses that is listed in Step 3 of Attachment 1. Requirement R8 does not clearly identify the data storage requirements for DDR with continuous recording capability. A 3-year period of continuous recording data per DDR location is too onerous. DDR continuous recording capability should be a minimum of 10 days per site. DDR recording(s) retained as evidence should strictly be limited to event-triggered recording by a system disturbance and where the RC, RE, or NERC requests data for the event within the 10-day time frame. Requirement R11.4's required conformance with IEEE Standard C37.111-"2013" is too onerous. This Requirement disqualifies the majority of FR and DDR equipment presently deployed. Seminole recommends revising the Requirement to require the use of IEEE Standard C37.111-"1999" or later.
Individual
Scott Langston
City of Tallahassee
No
see response for question 3
No
see response for question 3
TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes

Yes
In both R3 and R4 it appears the applicability is for Transmission Owners and Generator Owners but the GO typically does not own a substation bus, transformer with a low-side of >100 kV, or transmission lines (as a registered entity of GO). We believe Generator Owner should be removed from these requirements. In R5 please consider the following modifications: R5.1.2, bullet 1 – Add “as judged by the Responsible Entities” to the end of the bullet. R5.1.2, bullet 5 – Add “as judged by the Responsible Entities” to the end of the bullet. R5.2.2 – Add “within the past 10 years” to the end of the requirement to provide a reasonable and finite time frame. The NSRF interprets R11.2 to say that NERC/Regions will always submit a request for data within 10 days of an event, so it is not necessary for DME’s to hold data longer than that timeframe. As this impacts the memory/storage capability of the equipment we would appreciate clarification as to how the 10 days was determined and if the SDT believes the timeframe is long enough.
Group
Colorado Springs Utilities
Kaleb Brimhall
Yes
Yes
Thank you SDT for your efforts we voted negative for the following reasons: This standard brings 20% of our buses into scope, which means it will bring 20% of just about everyone's buses into scope (some large companies could have hundreds of buses included). Is that really the SDT's intent? It sounded like the SDT is not expecting it to be that big of an impact. The MVA threshold needs to be re-visited to prevent excessive, unmerited impact. We do not believe that it is logical to include a bunch of buses from smaller entities that just barely cross the threshold and then only include the top 20% of companies with buses having orders of magnitude greater short circuit duty. How can the inclusion criteria be modified to make sure that we capture the appropriate points of the system based on actual risk and impact to the BES? The current criteria is too inclusive and too generic - which impacts industry unnecessarily without getting the desired result. Thank You! Bottom line, IMO, the technical basis for this standard is flawed.
Individual
Brett Holland
Kansas City Power & Light
No
See comments at end of form.
No
See comments at end of form.
We suggest that the DMSDT further clarify the Applicability of the Functional Entities in 4.1 by including a statement in the Rationale Box for Functional Entities that when Responsible Entity is used in PRC-002-2, it specifically refers to those entities listed under 4.1. This is a slightly different approach than usually taken in Applicability. Some drafting teams have adopted a convention of hyphenating terms such as 30-, 60- and 90-calendar days. We suggest the DMSDT do the same. Similarly, ‘30-cycle post-trigger’ should also be hyphenated. We also noted that in the redline, step-up transformer was hyphenated in some places and not others. However, in the clean copy of the standard it is not hyphenated. We believe it should be. We suggest modifying the first sentence of Requirement R8 such that it reads: ‘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.’ There are a couple of instances in the 3rd paragraph of the Rationale box for R11 where 10 days is used. We believe this should be 10-calendar days. We suggest the following replacement for the 2nd item under Step 7 of Attachment 1. ‘If the list has 1 to 11 BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.’
Individual

Amy Casuscelli
Xcel Energy
Yes
In general, several requirements stacked into one can lead to missed activities/compliance issues, but we defer judgment on this to the NERC Standards Committee review and standards development guidelines.
Yes
We still believe the "Responsible Entity" should be consistent across the Interconnections. We recommend changing this to be the Reliability Coordinator for all Interconnections.
Xcel Energy engineers have conducted a test application of the selection criteria in Attachment 1, and have concerns that some locations are identified but provide little or no value (e.g. situations where fault recording is required for busses at both ends of a short line and one of the busses has only two sources (see diagram provided separately via email to the NERC SDT Coordinator for this standard)). We recommended an ‘exception’ written into the requirements with the Responsible Entity (or RC or Regional Entity) concurrence. In R5 – please clarify if the IROLs are those established by the TP, PC, or RC. (Also note that RC established IROLs may be in the operating horizon with little or no time for entities to actually install equipment). R12 should be reworded to state “…or develop and submit to the Regional Entity…” and end after “…(CAP).” R12 – is it inferred that entities can conduct maintenance on these devices (ie – out of service) as long as they meet the 90 day requirement? If so, consider making that clear.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
No
Note that AECI agrees with the current PRC-002-2 R5.1.2 Bullet#1 wording related to Flowgates, and appreciates this SDT's being thoughtfully responsive to prior comments. FOR: PRC-002-2, R5.1.2, Bullet #5 REMOVE: “or relatively low Available Transfer Capability (ATC)” RATIONALE: AECI believes calculated ATC is based upon many complex factors that are somewhat subjective, primarily Market related, and therefore a technically weak indicator for locating where reliability-related DDR equipment should be located.
FOR: Appendix #1, Step 6, Paragraph 2 REPLACE: “buses with the highest” WITH: “bus with the highest” RATIONALE: Clarity – As this process step seems to yield one identified bus, presumed to fill the void of its successor bullet’s 10% minimum count, the use of “required at” in conjunction with “buses” is confusing. FOR: PRC-002-2, R5.2, Guidelines AECI believes the guideline for 5.2 should provide sample calculations for the number of DDRs required: 1) for an entity having 5999 MW Historical Load, and 2)for an entity having 6000 MW Historical load. While we believe the answer for 1) is only 1 DDR, and for 2) 2 DDRs per R5.2, the Webinar presenter mentioned some expectations for Rounding which introduced uncertainty that the above example could address.
Group
Santee Cooper
S. Tom Abrams
Individual
Karen Webb
City of Tallahassee
No
Please see comment for question 3.
No
Please see comment for question 3.
TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.

Individual
Alshare Hughes
Luminant Generation Company, LLC
Yes
Yes
(1) Requirement R11, subsections 11.3, 11.4 and 11.5 includes prescriptive details regarding data recording and reporting. The goal of the standards development process is to develop Results Based Standards. These items are completely administrative in nature and are not results based. An entity could make a typo in formatting or when naming a file and be non-compliant with the requirement. These requirements should be removed from the standard or relocated to reference documents as described below. (2) Requirement R11, subsections 11.4 and 11.5 reference IEEE standards and software formats which are not subject to the NERC procedures for standards development and are not under the purview of the legally authorized regulatory authority. Thus these sub-requirements have no valid standing in a NERC Reliability Standard. These items are more appropriate for a reference document. Inclusion in a reference document seems to provide a better location to document specific details on requested data and can provide a more effective mechanism for revising these details at a later date in regards to the data reporting. (3) Requirement R11, subsection 11.4 specifically references "IEEE C37.111-2013". Some older DFRs that effectively capture the needed data may not meet this requirement for the 2013 software update. Software updates may not always be reasonably accomplished with equipment, service contracts or other factors. This specificity is administrative in nature and does not contributed to a results based standard. This version requirement should be revised to allow for any software versions that the entity has access to that supports the recording and report requirements.
Individual
Dan Roethemeyer
Dynegy
No
The DDR requirements for GOs are more prescriptive than other regional Criteria or Regional Standards (i.e. NPCC). Recommend the 500 MVA limit be increased.
Individual
Michael Moltane
ITC
Yes
Yes
ITC feels that the Requirement 10 specification of + 2 milliseconds of Coordinated Universal Time (UTC) is too restrictive for a number of industry wide installed modern microprocessor based relays. These relays have proven to be reliable from a protection, SER, and FR perspective. Additionally, the present PRC-018 standard indicates that a DME's clock shall be synchronized within 2 ms. ITC agrees the PRC-018 synchronism requirement would be acceptable for SER device clocks but not data. It is recommend that the DMSDT consider changing the tolerance level for breaker status SER to be within 10 milliseconds. This would allow the continued use of these microprocessor based relays. This will be consistent with DMSDT guidance that microprocessor relays are acceptable implementations of SER and FR.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes

These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
No
We agree that DDR data should be obtained for the transmission lines from generation plants as listed in requirement 5.1.2, but not that GOs are the parties that should collect this information. DME in general should be a topic for TOs and not GOs. TOs interpret and use DME data; GOs do not. TOs generally have wide-ranging arrays of DME, continuous recording/storage infrastructure, and experts in monitoring and maintaining such equipment; GOs do not. DDR data collected on the TO's side of the generation plant battery limits would be the same as that measured on the GO's side, so one could apply the same logic as is stated on p.33 of the standard for FR data, "For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection." Moreover, as regarding assignment of responsibility for monitoring disturbances, such events are more likely to originate in the transmission system (as was the case for the Northeast blackout of 2003) than in generation plants. The SDT emphasized in its discussion of 6/11/14 with the NAGF Standards Review Team that duplication of equipment is not mandated – a GO can contract with its TO to supply the data if the TO has DME at a plant or is willing to add such equipment. We are concerned that the SDT may not have considered the difficulty in negotiating such agreements for the provision of such data or the transfer of compliance responsibilities. A requirement in the standard that TOs must coordinate with generators to provide the data where they own DME at a generation plant would be preferable if GOs have any responsibility under the standard. The least-total-cost approach should be followed in obtaining the expected reliability benefits, and we believe that centralizing DME with TOs makes more sense than splitting the responsibilities between involved entities (TOs) and those who merely hand-over recordings (GOs) for further analysis. We recommend that the SDT perform a cost-benefit analysis of the two approaches before finalizing this standard.
See comments 3a-3c below. 3a. The Guidelines and Technical Basis Section of the standard states in the first paragraph on p.33 that, "SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data." The next section (Guideline for Requirement R2) states however that "Generator Owners are included in this requirement [for SER data] because a Generator Owner may, in some instances, own breakers connected to the Transmission Owner's bus." All generator output breakers connect eventually to the transmission system however, nor is it clear why the aforementioned lack of tripping time reliability for GO sequence-of-events monitoring would apparently apply in some cases (GO SER data mandatory) and not in others (GO SER data not required). 3b. The Guideline for Requirement R3 on p.33 states that "Generator step up transformers (GSU) are excluded from the above based on the following: - Current contribution from a generator in case of fault on the transmission system will be captured by FR data on the transmission system. - For faults on the interconnection to generating facilities it is sufficient to have fault current data from the transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed. The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data." This seems to fully exclude GOs from fault recording obligations, so why are GOs obligated in R3 and R4 to have FR data? 3c. Comments 3a and 3b above gain emphasis from the circumstance that it is expected that the Guidelines and technical Basis Section of the draft standard will be deleted if and when PRC-002-2 is voted-in and approved by FERC. That is, the logic by which GOs are sometimes in and sometimes out will be even more obscure than it is now. 3d. The requirements for GOs to "have" SER (R2), FR (R3 and R4) and DDR (R7) data are understood to mean that they do not need to own this equipment, and it would do just as well to have an agreement with the TO to fulfill the PRC-002-2 requirements if and where the TO already has DME on their side of the generation plant fence. This point does not come across clearly in the present text of PRC-002-2. There should be a footnote saying that "This standard defines the 'what' of DDR, not the 'how.' GOs may install DME or, where

the TO already has suitable DDR, contract with the TO." It would be still better to just drop GOs from the picture, however, per our comments above.
Group
SPP Standards Review Group
Robert Rhodes
Yes
Yes
We suggest that the DMSDT further clarify the Applicability of the Functional Entities in 4.1 by including a statement in the Rationale Box for Functional Entities that when Responsible Entity is used in PRC-002-2, it specifically refers to those entities listed under 4.1. This is a slightly different approach than usually taken in Applicability.
Some drafting teams have adopted a convention of hyphenating terms such as 30-, 60- and 90-calendar days. We suggest the DM SDT do the same. Similarly, '30-cycle post-trigger' should also be hyphenated. We also noted that in the redline, step-up transformer was hyphenated in some places and not others. However, in the clean copy of the standard it is not hyphenated. We believe it should be. In some places in the documentation three-phase is hyphenated and in others it is not. While we think it should be, we encourage the DM SDT to be consistent. 'Disturbance' is defined in the NERC Glossary and depending upon its usage should be capitalized. The DM SDT needs to be consistent with its format. In the 2nd line of M3, insert 'that' in between 'data' and 'is'. In the 3rd line of the 1st paragraph in the Rationale Box for R5, it would be appropriate to use BES rather than spelling out Bulk Electric System. Add a hyphen to 'high-' in the 3rd line of the Rationale Box for R7. This is consistent with usage throughout the rest of the documentation. We suggest modifying the first sentence of Requirement R8 such that it reads: '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.' There are a couple of instances in the 3rd paragraph of the Rationale box for R11 where 10 days is used. We believe this should be 10-calendar days. Also, in the next to last line of the last paragraph 'disturbance recording' is capitalized. It is not a defined term in the NERC Glossary and shouldn't be capitalized. This change needs to be made throughout the documentation. In the 6th line of the Rationale Box for R12, 'entity' should not be capitalized. In the VSLs for R2, insert 'Owner' between 'Transmission' and 'or' for consistency throughout the VSLs for the other requirements. We suggest the following replacement for the 2nd item under Step 7 of Attachment 1. 'If the list has 1 to 11 BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three-phase short circuit MVA as determined in Step 3. Proceed to Step 9.' 'Disturbance monitoring' is capitalized in the Introduction of the Guidelines and Technical Basis Section. Since it is not a defined term in the NERC Glossary, it shouldn't be capitalized. Modify the next to last line of the 1st paragraph in the Guideline for Requirement R1 to read '…voltage and current for individual circuits allow precise reconstruction of events of both…' Change 'disturbance' to 'disturbances' in the next to last line of the 2nd paragraph. In Item 6 on Page 32 (clean version) of the same section, insert 'to those' between 'buses' and 'with'. In the 6th bullet under Item 8 on the same page, change 'Owners'' to 'Owner's'. Hyphenate 'in-effect' in the 1st line of the 2nd paragraph of the Guideline for Requirement R3. Modify the 1st line of the Voltage Recordings section on Page 34 (clean version) to read 'Voltages are to be recorded at applicable BES buses. Note that Requirement R3 calls for the…' Delete the 's' on 'meets' in the 2nd line of the 1st paragraph of the Guideline for Requirement R4. Change 'captured' in the 1st line on Page 35 to 'captures'. In the 2nd line of the same paragraph, set the phrase 'when time synchronized to a common clock' off with commas. Delete the last sentence of the 1st full paragraph on Page 36 (clean version). It is a duplicate. Insert an 'a' between 'after' and 'fault' in the 1st line of the 1st paragraph under Guideline for Requirement R6. Replace 'has' with 'with' in the 3rd line of the 1st full paragraph on Page 37 (clean version). Near the end of that same line, there appears to be an extra space between 'Bus,' and 'would'. Skip a line and hyphenate 'in-service'. Capitalize Real Power and Reactive Power here and in the last paragraph before Guideline for Requirement R7. Add a hyphen to 'high-' at the end of the 1st line under Guideline for Requirement R7. Hyphenate 'short-term' in the 2nd line of the 1st paragraph under Guideline for Requirement R9. In the 4th line of the 2nd paragraph, insert an 'a' between 'in' and 'sampled'. Capitalize 'Requirement R1' and 'Requirement R5' in the 3rd line of the 1st paragraph under Guideline for Requirement R11. Delete the 'a' in front

of ‘Day 1’ in the 6th line of the 3rd paragraph under Guideline for Requirement R11. Insert an ‘and’ and delete the ‘it’ in the 2nd and 3rd lines of the 2nd paragraph on Page 40 (clean version). That portion of the sentence should then read ‘…Transient Data Exchange and is well established in the industry.’ Split the 2nd sentence of the 3rd paragraph on Page 40 (clean version) into two sentences such that it reads ‘…Naming Time Sequence Data Files. The first version was approved in 2007.’ In the 4th line of the 3rd paragraph on Page 40 (clean version) replace ‘was’ with ‘were’. Hyphenate ‘out-of-service’ in the paragraph under Guideline for Requirement R12. Also, there appears to be an extra space between ‘develop’ and ‘a’ in the 10th line of the same paragraph.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Individual
Chris Mattson
Tacoma Power
Yes
Tacoma Power disagrees with the need for this standard. However, assuming that this standard will likely proceed to approval, Tacoma Power takes no exception to merging these requirements.
No
It is unclear what requirements for DDR data changed. The redlined version has only superficial changes to Parts 5.1 and 5.2. Tacoma Power has some concern about the fourth bullet under Part 5.1.2: “Interfaces between Balancing Authority Areas.” While this is only one guideline that the Responsible Entity should (not must) consider, it could potentially place disproportionate burden on entities with a relatively small Balancing Authority Area.
Tacoma Power disagrees with the need for this standard and believes there are more cost effective alternatives for acquiring the data necessary for event analysis. However, assuming that this standard will likely proceed to approval, we are providing both comments for improving the draft standard and an explanation for why we believe this standard is not the appropriate method to address the perceived needs. a. Under Measurement M3, change “…of FR data is…” to “…of FR data that is…” b. Under Measurement M11, change “…evidence (electronic or hard copy) data…” to “…evidence (electronic or hard copy) that data…” c. What if FR, SER, or DDR equipment is taken out of service for maintenance and/or testing. Could this result in an automatic violation of Requirement R11, Part 11.2? Or, should this be treated like a failure under Requirement R12? d. In Attachment 1, Step 7, for cases in which the list has 11 or fewer BES buses, change “…at the BES buses with…” to “…at the BES bus with…” e. Please confirm that only the channels that trigger need to be provided upon request and that no cross-triggering between FR or SER is required. f. Requirements R3 and R4 should require the capability to record data rather than requiring data. g. The VSLs for Requirement R10 should be based on the number of missed electrical quantities rather than the number of BES buses. Otherwise, please provide guidance on how a substation with several relays correctly time stamped but one relay with an incorrect time stamp should be treated. h. Requirement R10 should be modified to have SER timestamping to +/- 40 milliseconds while maintaining the FR and DDR timestamp of +/- 2 milliseconds for two reasons. First, the breaker position indication using 52a or 52b contacts can be different than the main contacts opening and ultimate current interruption by more than 2 cycles. Typical, 52a vs 52b contacts are at least ½ of a cycle apart. Timestamping the relay input to 2 milliseconds will not actually indicate the state of the power system. Second, SEL 300 series relays timestamp SERs to the nearest quarter cycle, so a large number of installed relays would not meet the requirements for SERs. These relays do timestamp the FR to the specified accuracy, just not the SER. Alteratives to this draft standard: The 2003 outage report outlined major deficiencies with event recording, but the data recording technology has dramatically changed in the last decade. Even though no standard was in place specifying data recording, utilities have been installing GPS time stamped event recording based on

business drivers. As outlined during the CEAP report, the labor for event report alignment was reduced from 4,400 person-hours for the 2003 outage to only a week for the 2011 southwest outage. Although further reductions in event analysis SME hours would result from this standard, the compliance SME hours would dramatically increase and result in overall higher costs. As outlined in the CEAP report, most utilities already have event recording in place, or are going toward recording as part of multifunctional equipment installations. Therefore, ignoring automated event collection, the only costs that should be considered are due to the increment burdens of documenting compliance with this standard. Instead of this standard, we believe that a NERC guidance document on event reporting best practice would be equally effective while requiring very little compliance burden. In other areas, NERC is moving away from standards that require zero defects in high volume tasks. This standard requires 100% accurate time stamping of 100% of a small portion of elements, but then ignores 80% of BES buses. On a voluntary basis, we have approximately 50% of elements monitored. Thus if we supplied only the event reports required by the standard, the coverage of our system would go down dramatically. In order to meet the zero defect policy of this standard, we will have to redirect efforts from actual event analysis to documentation of event recording capability. If data recording is implemented as a standard instead of a best practice guideline, it sets the minimum bar instead of the optimal goal. Most utilities already have at least a marginal level of recording capabilities. We would prefer NERC to aim higher. The best event records occur when all data channels at a substation are recorded for a trigger on any channel for any kind of transient, including frequency or overvoltage. This level of recording is impractical to require as a standard but is already in place for many utilities. For an enforceable standard, we agree that undervoltage & current are the only reasonable triggers to require. We are concerned that the SDT appears to have based installation cost assumptions on the premise of using data stored locally on relays. If this is an enforceable standard with a zero defect requirement, utilities are in essence forced to automated event collection from relays in order to guarantee zero defects. This automated event collection then brings in large costs for communications, and for applying CIP standards to those communications. If this were a best practices document, or allowed some data gaps, local relay storage would be a reasonable assumption.
Individual
John Brockhan
CenterPoint Energy Houston Electric, LLC
Yes
Yes
1) Regarding R2, CenterPoint Energy believes that breaker open/close operations obtained from the EMS system time-stamped based on RTU scan is adequate SER data for the initial stages of event analysis before detailed disturbance data is obtained from the FR and DDR data that is ultimately required for the actual event analysis. Therefore, CNP recommends removing SER data from R10. 2) Requirement R3 states "...shall have the following FR data to determine the following electrical quantities for each of the BES Elements they own connected to the BES Buses identified in Requirement R1:". CenterPoint Energy believes this language causes confusion with regard to "determining" phase-to-neutral voltages for each phase of each specified BES Bus as required by Part 3.1. The BES Bus voltage can be "determined" by measuring/recording each phase-to-neutral voltage of each line, or by measuring/recording each phase-to-neutral voltage of a smaller subset of lines connected to a BES Bus. The Guidelines and Technical Basis Section describe measuring voltages of "each" line. For entities that are using dedicated fault recording devices, channel capacity can be an issue. In some installations, voltages from 2 or more lines, i.e. a subset of the total number of lines connected to the BES Bus, can be recorded to provide adequate phase-to-neutral voltage FR data for system disturbances obviating the need to record each phase of each line at the recorder. CNP recommends that the DMSDT reconcile the Guidelines and Technical Basis Section language with the Part 3.1 language such that BES Bus voltages can be "determined" by measuring a number of line voltages based on engineering judgment.
Individual
Kayleigh Wilkerson
Lincoln Electric System

Per Attachment 1, Step 1 utilities are instructed to “Determine a complete list of BES buses that it owns.” A complete list of BES buses could include tap buses feeding radial load where there would be no BES circuit breakers or relaying and therefore no ability to gather the data pertinent to this standard. The SDT response to LES’ previous comments stated that, “If a tapped substation was not modeled in a system study as a bus then it would not be considered a bus.” If this is the drafting team’s intent, it should be clearly stated in Step 1 that tap buses with no BES breakers or relaying are not to be included. Doing so eliminates any possible confusion associated with whether a bus has been included in a system study. Whereas a Planning study model may not include these buses, a System Protection study model would in consideration that non-BES transformer relaying at the tap has to be coordinated with relaying at adjacent substations. R11.2 specifies “The recorded data will be retrievable for the period of 10 calendar days preceding a request.” For clarity, LES suggests restating R11.2 as follows: “The recorded data will be retrievable for the period of 10 calendar days following the date that the data was recorded.” Wording it this way ensures that the 10 calendar day timeframe starts on the day that the data was recorded. If left unchanged, the existing statement would tie the 10 day timeframe to the date of the request which makes the timeframe indefinite given the fact that the requesting entity has no time limit on when a request can be made.
Group
SERC Protection and Controls Subcommitee
David Greene
Yes
No
(1) R 5.1.2. Still seems open ended for us. The following bullet points under this requirement give reasons for concern: • Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection • Interfaces between Balancing Authority Areas • Areas of significant congestion, thermal violation history, or relatively low Available Transfer Capability (ATC) DDR are applied for stability reasons, so thermal violations, and low ATC are not valid justification. (2) Depending on how our Planning Coordinator interprets these points, we could still be put upon to install an indeterminately large number of PMUs. This language *is* a step in the right direction from the previous draft of the standard, where "all permanent Flowgates" required DDR equipment, however, our preference would still be to delete R 5.1.2 from the standard. (3) If 5.1.2 is retained, please add a section 5.3 “The number of BES Elements need not exceed one per 1000 MW of its historical peak system Demand.” This provides sufficient coverage in the Responsible Entity’s area and encourages the RE to be ‘responsible’ in applying the 5.1.2 guidelines. (4) Some software vendors do not presently have the full capability as described in Requirement 11 implemented in their equipment or DME application software. This could require change out of the existing equipment. (5) Please clarify the 3rd paragraph of Rationale for R5 by adding ‘only one’ so its consistent with Guidelines and Technical Basis section page 36:’For “major transmission interfaces” with the exception of HVDC, the DDR data is to be captured for only one BES Element, and, is obtainable from one terminal (either end) of an Element.’ Also add: ‘If the BES Element has multiple owners, each TO and / or GO will need to agree which owner will have the DDR data, and the other owners can refer to this agreement as their means of meeting their obligations.’ (6) Please add ‘If the BES Element has multiple owners, each TO (and / or GO, as appropriate)will need to agree which owner will have the DDR data (or equipment, as appropriate), and the other owners can refer to this agreement as their means of meeting their obligations.’ In the rationales for R6, R7, R8, R9, R10, R11, and R12 to be consistent with R5 and cover tie line Elements. Similarly, M6 through M12, add the option that for BES Elements with multiple owners, the TO / GO can provide an agreement stating which owner is responsible for the DDR data. (7) The standard should include direction if agreement between entities cannot be reached i.e. “In cases where agreement between entities cannot be reached, the TO/GO that necessitates DM capability is ultimately responsible for the equipment and any /all requirements.”
The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Group

JEA
Thomas McElhinney
The 1500MVA threshold is too low and needs to be increased.
Group
ISO RTO Council Standards Review Commitee
Greg Campoli
No
We agree with the merging of R2 into R1, but not the revised R5 which combined R6 and R7. Please see our comments under Q2, below.
No
Please clarify in R5 whether the first use of the term "BES Elements" is intended to be used here. It appears the intent is that the responsible entities notify all owners of the BES facilities connected to the BES Buses which they have identified. In that case, that term should be "BES Buses" or both BES Elements and BES Buses. We are concerned that the last bullet in Part 5.1.2 may be interpreted to include congestion as it relates to commercial/economic use of transmission interfaces. The term "significant Flowgates" should be limited to only physical/electrical constraints and not congestion that can be mitigated by market mechanisms. Part 5.1.4 needs to clarify whether BES Elements associated with the Interconnected Reliability Operating Limit should include only the monitored element or the contingent element or both. The Rationale for R5 should include the technical reason why the "Responsible Entity" is the applicable entity for identifying buses/elements for DDR events. As stated in the Background Information of the Comment Form, the SDT states the PC or RC has the overall view of the BES for DDR. This explanation should be included in the standard. R5 is also confusing in what is the requirement for BES Element owners which have been identified as needing DDR. We recommend the following changes to ensure the DDRs are applied on the proper BES Elements: " Each Responsible Entity shall (i) identify BES Elements for which dynamic disturbance recording (DDR) data is required, (ii) notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements WILL require DDR data upon request of the Responsible Entity, and (iii) reevaluate the identified buses at least once every five calendar years. " We are also concerned that this requirement envelopes 3 distinct and mutually exclusive requirements, each of which apply to distinct registered entities and each having different measures. This should be separated into three requirements which will also make the measures for VSL and VRF more applicable. The distinguishing of requirements for clarity in applicability and measurement should be included as an element of the "Quality Review" prior to industry comment posting. R5.1 – The BES Elements that require monitoring shall include the following… R5.2 – The BES Elements that require monitoring in each Responsible Entity's area shall include a minimum of… R5.1.4 requires monitoring BES Elements associated with IROLs. The requirement should only apply to IROLs that are voltage or stability limited: "One or more BES Elements associated with IROLs that are based on voltage or stability performance."
Attachment 2: acceptable states are OPEN or CLOSE but other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also commonly used. The format should allow for regional variations in terminology. Otherwise, it could become time consuming for TOs and GOs to provide the SER data.
Individual
Chris Scanlon
Exelon Companies
No
Exelon does not agree with the SOE/FR requirements as written but not because of the merging of the R2 and R1 requirements. We believe that there needs to be a streamlined process for entities that are modernizing their system. The SOE and FR portions of this standard are very close to 100% burden to entities that are utilizing modern microprocessor relays connected to GPS clocks for T-lines on their system as a standard. The proposal does not account sufficiently for technical changes that have occurred over the last ten years. The Attachment 1 process is overly burdensome for entities modernizing their systems. An alternative to the attachment 1 process is for an entity to

identify that 40% of its BES transmission lines (transformers need not be monitored if lines are monitored) include FR and SER capability. This would be easy to demonstrate as these types of lists are readily available already. Additionally, we believe the reference to BES Elements / Busses needs clarification. We also object to the TO having the responsibility to notify others of their need to comply with a NERC standard, "notify other owners of BES Elements connected to those BES buses".
Yes
No Commnet
R1: See comments to question 1. R2: It is not necessary to monitor circuit breaker auxiliary contacts to figure out when a circuit breaker opened or closed. Loss of current can be monitored in a fault recorder. This requirement puts a high burden on identifying print #s to show circuit breaker auxiliary contacts are connected to relays with SER capability. This effort is just not necessary based on our experience investigating thousands of operations over the years. The drafting team should eliminate this requirement or modify it to clearly state that cessation of current can be used to determine when circuit breakers open. R3: T-lines are exposed to a much higher number of faults/operations than T-transformers. Thus, modernization of T-line protection provides the greatest increase to reliability by a large margin. Having modern relays on T-lines allows for deducing current in transformers if necessary. The drafting team should concentrate on lines rather than transformers as the industry is doing. The drafting team should remove transformers from R3 since this information can be deduced from line monitoring or change R3.2.1 to state Transformers… “only when sufficient line monitoring is not present to derive transformer quantities”. R4: No comment, previous changes made by the drafting team addressed our concerns. R5: No comment, previous changes made by the drafting team addressed our concerns. R6, R7, R8: No comment. R9: The drafting team should eliminate requirement 9.1 unless they are aware of a significant portion of the industry installing equipment that doesn’t meet this requirement. To our knowledge, the main manufacturers of this equipment all easily exceed this requirement. R10: The drafting team should eliminate the requirement of within +/- 2 msec of UTC unless they are aware of a significant portion of the industry installing equipment that doesn’t meet this requirement. To our knowledge, the main manufacturers of this equipment all easily exceed this requirement. R11: No comment. R12: We’re using microprocessor relays for FR and SOE capability. They are tested under PRC-005 and alarmed upon failure. We should not have to keep track of every relay that fails on the system that we fix or replace for this standard. We have plenty of incentive to keep our relays working already and we don’t run with failed relays for 90 days. Hence, there is no need for R12 and it should be eliminated. It is 100% burden, a complete waste of engineering resources, and hence a detriment to overall reliability. If the drafting team will not eliminate this requirement, it should be re-worded such that it is very clear that we do not need to keep track of failures that are rectified within 90 days. We should not have a compliance burden to prove that we fixed something in 2 days. An overall comment is that we believe this standard is not required for FR and SOE. These functions are built in to modern relays being adopted industry-wide already. All the requirements related to FR and SOE should be eliminated and the standard written to address DDR only. It is even arguable that this standard is required to promote DDR capability as the widespread use of synchrophasors including their storage has greatly expanded since 2003.
Individual
Oliver Burke
Entergy Services, Inc.
Yes
No
We agree with the revised DDR location criteria reducing the number of monitored BES Elements and appreciate the DMSDT efforts to address that issue. However we are still concerned about the potential for an unnecessarily excessive number of required DDR locations with regard to Flowgate applications. We believe the proposed minimum criterion of “One additional BES Element for each additional 3,000 MW of its historical peak system Demand.” does specify a reasonable lower threshold which provides adequate wide area coverage and also believe there should be a similarly defined upper threshold on the number of DDR Flowgate (or DDR total) locations required. Suggest DDR Flowgate location criteria be revised to specify no more than twice the adequate minimum number of locations as follows: “Stability related interfaces or other significant Flowgates in the

NERC Book of Flowgates for the Eastern Interconnection (prioritized by the Responsible Entity with area coverage considerations and with a total of no more than one BES Element per 1,500 MW of its historical peak system Demand),"
Entities with a significant number of DDRs and have DDRs which include installations where manual data retrieval is necessary should be allowed more than 30 days to collect, format, assemble and review data for submittal. Add provision for a data request submittal extension such as "R11.1 The recorded data will be provided within 30 calendar days of a request unless an extension is granted by the requesting authority."
Individual
Bill Fowler
City of Tallahassee
No
see comment for question 3
No
see comment for question 3
TAL believes that this standard is not justified, either from technical or cost benefit perspectives, and we believe that measurement devices for purposes of post-mortem analysis of events ought to be addressed through guidelines rather than a standard.
Individual
Don Schmit
Nebraska Pubilic Power District
No
R1 should have some explanation for what the implementation/installation deadlines are for newly identified BES buses as part of the 5 year review. R1 states "reevaluate the identified BES buses at least once every five calendar years", should this read "reevaluate all BES buses at least once every five calendar years"? It seems that new buses may be added and existing buses in the required locations for FR may get dropped down the list and become discretionary. R2 rational states "time stamped according to Requirement R10 to a common clock, provides the basis for assembling the detailed sequence of events timeline of a power system disturbance." Since relays and FR recorders often use separate clocks consider changing "common clock" to "time synchronized clock". R7 states: "Each Generator Owner shall have DDR data for each BES Element it owns and is notified according to Requirement R5". Should this read "Each Generator Owner shall have DDR data for each BES Element it owns as notified according to Requirement R5" instead? It seems a bit confusing how to read this requirement. It could be read that the GO "shall have DDR data for each BES Element it owns". Consider if this requirement can be clarified or restated.
No
For R5 if the Responsible Entity is slow in notifying owners where DDR data is required does this force the owners to meet the same implementation deadlines or can they extend the deadlines by the same amount of time the RE was late in getting a notification out to the owners? I bring this up because the BES owners will not have any control over the RE schedules but could be subject to shorter implementation deadlines. In addition, since there is some open ended latitude in the ability of the Responsible Entity to identify locations for DDR it is possible that large number of locations could be identified to install DDR in some areas. If this were to occur would there be a possibility for the BES owners to request additional implementation time to become compliant? Consider if some clarification could be added. One option might be to have criteria in 5.1.2 less open ended without any latitude.
It appears, for example, GSU 13.8kV generator buses that exceed the 1500MVA fault current level should be in the bus fault list for FR evaluation. If this is correct they are often ungrounded systems. Can the FR voltages and currents be monitored on the high side of GSU or a tie transformer with a BES tertiary reactor? It seems unclear what currents would be required to monitor as there would not be any ground current at these types of locations/buses if the ungrounded low side must be monitored. R3 and R4 don't specifically mention GSU transformers, GSU low side buses or BES tertiary buses which tend to be ungrounded systems. Can the drafting team clarify that for tertiary or GSUs where the generator bus (for example 13.8kV) is identified in the list of fault buses that it

would be acceptable to monitor the voltages and currents on the high side of the GSU or tie transformer? If not, clarify that only the three 13.8 line to ground voltages or 13.8kV line to line voltages are required but not the currents or at least not the ground current. Note that the option of line to ground or line to line voltages is suggested above. Some ungrounded buses may not have line to ground voltages. This may be a concern for some utilities. It seems a bit odd the DDR would be allowed to be on the GSU high side yet still require FR data using the generator bus side voltages as the standard appears to read. R7 seems to address the high or low side requirements better for DDR but clarification for what is required for GSU and generator buses for FR would be helpful since they are often ungrounded systems. For R11 it states: “Each Transmission Owner and Generator Owner shall provide all SER, FR, and DDR data for the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 to the Reliability Coordinator”. Consider clarifying this wording since it appears to require DDR data is required for R1 to be provided to the RC. R10 also appears to have this concern as well. DDR data is not required by R1, but through the use of the word “and” in R10 and R11 it appears that DDR recording may be necessary on these buses. R12: Is the CAP required to be submitted to the RE or is it upon request similar to the records? This requirement seems like it would be difficult to audit since it would be tracking work on a utilities system. I wonder if the RE is prepared to monitor this information. If they do plan to monitor this is there any other process format or forms necessary or is it understood to be an informal case by case transmittal of CAP status?
Individual
John Pearson
ISO New England
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
Yes
We agree with the concept of the requirement, however, we suggest moving the methodology for selecting DDR locations described in 5.1 and 5.2 to an attachment and not include it within the text of the requirement itself (similar to the SER/FR bus selection methodology in Attachment 1 for R1).
1. R1 VSL – The percentage and time basis language in the first two parts of the VSLs are confusing: it’s unclear what the percentages are referring to and what time period the assessment is being measured to. Also, the term assess is not used in the requirement or Attachment 1. The third part of the VSL is clear. Suggestion to change VSL language for the first two parts to the following language across all severity levels in the table: “The Transmission Owner identified BES buses as directed by Attachment 1 for more than 80% but less than 100% of the BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement 1 but was late 30 calendar days or less for the once every five year requirement.” 2. R5 VSL – The percentage and time basis language in the first two parts of the VSLs are confusing: it’s unclear what the percentages are referring to and what time period the assessment is being measured to. Also, the term assess is not used in the requirement or Attachment 1. The third part of the VSL is clear. Suggestion to change VSL language for the first two parts to the following language across all severity levels in the table: “The Responsible Entity identified the BES Elements as directed by Requirement R5 for more than 80% but less than 100% of the BES Elements included in R5.1. OR The Responsible Entity evaluated the BES Elements as directed by Requirement 5 but was late 30 calendar days or less for the once every five year requirement.” 3. For R3.1 – Attachment 1 states that a ring bus or breaker-and-a-half bus are considered as a single bus. Will the SDT please clarify does this mean that in a ring or breaker-and-a-half substation, only one bus needs to monitored for R3.1? 4. For R11 – We suggest moving the language describing specific formatting requirements in R11.3 through R11.5 to the Guidelines and Technical Basis section of the standard as it is administrative in nature and not performance-based. 5. For R12 – Has the SDT discussed having the entity reporting FR/SER/DDR failures report to the Responsible Entity as well as the Regional Entity, so that the Responsible Entity can look at possible alternative methods to monitor the Elements identified per R5? There may be a reliability gap if the Responsible Entity is not notified due to no requirement for the GO or TO to do so. 6. R11 VSL - The Requirements refer to days and the VSL language refers to percentages. We

ask the SDT to confirm that the interpretation of R11 VSLs below is correct. If so, we suggest changing the VSL language to the language provided below. If not, please provide the correct interpretation and possibly revised language to help assure there aren't inconsistencies in compliance and enforcement application. Lower VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 9 days but less than 10 days of the requested data. Moderate VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 8 days but less than 9 days of the requested data. High VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided more than 7 days but less than 8 days of the requested data. Severe VSL: The Transmission Owner or Generator Owner as directed by Requirement 11, Part 11.2, provided less than 7 days of the requested data.
Group
Seattle City Light
Paul Haase
No
R1 does not meet NERC principles for world-class Standards, because it includes three separately audited control activities in a single sentence: (1) identify buses, (2) notify others of buses, (3) reassess every five years. If this draft Standard is deemed necessary, Seattle recommends rewriting R1 to include three subrequirements as follows: R1. Each Transmission Owner shall: R1.1 Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1. R1.2 Notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days that those BES Elements may require SER data and/or FR data. R1.3 Reevaluate the identified BES buses at least once every five calendar years. In addition, the draft Standard does not clarify required actions should the five-year reassessment identify a different selection of buses for which monitoring now would be required. Seattle suggests that an implementation period be identified for installing SER and FR equipment for newly identified buses similar to the implementation time for the initial implementation of the Standard. Likewise, the Standard does not clarify how newly constructed buses are handled. Seattle suggests that that they be evaluated at the next 5-year reassessment, rather than individually as they are brought on line.
No
As for R1, R5 does not NERC principles for world-class Standards, because it includes three separately audited control activities in a single sentence: (1) identify Elements, (2) notify others of Elements, (3) reassess every five years. If this draft Standard is deemed necessary, Seattle recommends revising the first paragraph of R5 to include three subrequirements as follows: R5. Each Responsible Entity shall: R5.1 Identify BES Elements for which dynamic disturbance recording (DDR) data is required R5.2.Notify other owners of BES Elements connected to those BES buses, if any, within 90 calendar days, that those BES Elements may require DDR data R5.3 Reevaluate the identified buses at least once every five calendar years. And then renumber the remainder of the requirements to conform: 5.4 The BES Elements shall include the following: 5.4.1 Generating… In addition, the draft Standard does not clarify required actions should the five-year reassessment identify a different selection of Elements for which monitoring is required. Seattle suggests that an implementation period be identified for installing DDR capabilities for newly identified Elements similar to the implementation time for the initial implementation of the Standard. Likewise, the Standard does not clarify how newly constructed buses are handled. Seattle suggests that that they be evaluated at the next 5-year reassessment, rather than individually as they are brought on line.
Seattle appreciates the efforts of the Drafting Team to respond to comments received following the initial posting of this draft Standard. However, Seattle fundamentally disagrees with the approach proposed by draft PRC-002 for several reasons. First, the proposed Standard requires an entity to establish at least 43 new controls to meet the compliance assessment approaches identified in the draft RSAW, and this figure does not consider the dozen or additional controls required to ensure all Attachment 1 steps are met. For context, consider that approximately 4-5000 controls are required to meet the entire body of NERC Standards. As such proposed PRC-002 represents a 1% increase in the overall compliance burden on the electricity enterprise. Entities will be required to monitor performance of minor activities, and auditors likewise will be required to examine performance. Seattle does not believe the reliability benefit offered by this Standard warrants this new compliance

burden. Indeed each requirement of PRC-002 is identified as “Lower” for violation risk factor (the lowest rating possible), indicating that the drafting team does not consider any requirement of the Standard to have a critical impact on BES reliability. Rather this Standard supports long-term operational improvements in the BES. Seattle believes such improvements are important and supports a reasonable approach to disturbance monitoring, but does not support the complex, over-engineered Standard. The bus screening process is an example of a process that needs to be simplified. The rational does not seem to be well thought out and is certainly not easy to explain and implement (worse than the FERC Order 754 exercise that industry recently participated in). The attached Excel spreadsheet and the directions for completing it are very cumbersome and inefficient--a lot like trying to fill-out a Federal Tax form. Instead of giving an entity the metrics to be achieved, this approach attempts to create a cookbook format where data needs to be entered in one part of the spreadsheet, and then subtracted out in another part of the spreadsheet. Seattle believe appropriate and reasonable a general requirement to have disturbance monitoring, but believes the technical requirements for data type, frequency of sampling, and so forth would be better handled in a criteria or guideline document. Once such requirements are codified as federal law it is cumbersome and lengthy process to change them, yet all are aware how fast technical change has occurred in the area of disturbance monitoring. Moving the technical requirements from the Standard to a guidance document likewise would significantly reduce the compliance burden associated with the draft. Finally, Seattle requests technical justification by established for continent-wide application of a 1500 fault MVA threshold. Once established in a Standard, a technical justification will be required for any change; as such technical justification should be provided beforehand to establish the value as correct and appropriate. This value may be correct and appropriate for the NPCC area, but has not been justified in other regions. It may well be correct and appropriate, but a justification has not yet been provided.
Group
Florida Municipal Power Agency
Frank Gaffney
No
see question 3
No
see question 3
While FMPA appreciates the efforts of the SDT to address many of the specific comments received, FMPA’s position remains that a standard is not justified for Disturbance Monitoring. We believe that Disturbance Monitoring is better addressed through guidelines than through a standard. The system has changed a lot over the last 10 years since the Northeast Blackout of 2003 and we can gain much more information now from microprocessor based relays and phasor measurement units (PMUs) prevalent throughout the system. The justification for this standard is primarily based on the decade old Blackout Report and does not take into account the changes in system equipment since then. This justification was highlighted by the SDT’s response to FMPA’s prior comment about a standard not needed. SDT Response: “(1) The need for the development of a standard for Disturbance Monitoring was accentuated by the lack of information available to analyze the 2003 Blackout in the Northeast. From the August 14, 2003, Blackout Final NERC Report:…” Additionally, it should be noted that in the Executive Summary of the Cost Effectiveness Analysis Process (CEAP) Pilot for this project, the following statement was made: “The majority of CEA respondents believed the standard’s potential immediate reliability benefits were minimal.” So, with this CEAP observation along with the low approval rating of 43.29%, there is clearly some significant stakeholder concern with the justification for this standard. In light of the Paragraph 81 Project, the industry is supporting reducing and consolidating the amount of requirements. This standard meets several Paragraph 81 Criteria used to identify requirements for retirement including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. There are 12 requirements and over 20 sub-requirements in the current PRC002-2 draft. The amount of detail is unnecessary and poses a serious compliance burden on registered entities. While we do not believe the standard is needed, we strongly recommend that if this project goes forward, that the drafting team revise this standard to two or three requirements. We point out that the NERC Rules of Procedure have a detailed section on Disturbance Response Procedures – Appendix 8. While we recognize that the SDT has limited latitude in eliminating a project or veering from the SAR, we suggest that the Standard Committee

revisit the justification for this standard and at a minimum review the scope and prescriptiveness of the detailed requirements in light of the Paragraph 81 guidelines.
Individual
Gul Khan
Oncor Electric Delivery LLC
Yes
Oncor supports combining identification and notification into one requirement as done in the latest draft.
No
Oncor recommends an audit curtailment be added to the DDR requirement similar to what is used in Attachment 1 for the FR's and SER's.
General: It is understood the Rationale Boxes will be retained but relocated to the "Guidelines and Technical Basis Section" of the Standard. If the "Guidelines and Technical Basis Section" cannot be used as compliance validation to auditor(s), it is imperative the requirement language be paired to the alternatives specified in the Rationale language. Oncor identified several instances where the Rationale Boxes provided much needed clarity to the Requirement itself. Incorporating the Rationale/intent language into the Requirement or Measurement itself would further clarify the Requirements resulting in a clear and mutual understanding for both the Registered Entity and the auditor(s). Therefore, Oncor recommends the DMSTD review the Requirement/Measurement language and the corresponding Rationale language to ensure there are no gaps. Specifics are provided below: R2: Legacy FR equipment installed before the Standard effective date may not be capable of embedded SOER. R2 does not afford the same caveat for older equipment where SOER is required that R8 provides for older equipment where DDR is required. Language should be added to R2 providing the option to utilize FR digitals to monitor circuit breaker position for required circuit breaker position monitoring. R1 and R5: The Implementation Plan includes specific references to timeframes for becoming fully compliant with the locations lists after approval of the standard, but the Requirement language itself does not include post-implementation "5 year re-evaluation" compliance timelines for the required reassessments. "Re-evaluation time frame implementation" language should also be included in the affected Requirements to prevent any disparity following the initial implementation and departure from the Implementation Plan. R3 and R6: A Rationale should be added that the required "electrical quantities can be determined (calculated, derived, etc.)" to R3 and R6 as described below: • The R3 Rationale explains the method of deriving electrical quantities. The language of R3.1 does not reflect the intent described in the Rationale. Specifically, whether locations where busses are effectively tied together, such as on ring or breaker-and-half bus configurations, can derive the required phase-to-neutral voltages by monitoring a minimum of two of each Phase-to-Neutral voltages, from either line terminal or bus potentials. In a typical large switching station, this could eliminate costly retrofits to literally provide all three phase-neutral voltages for "each line or bus." • The language of R6.3 does not specify the method used to provide "Real Power and Reactive Power flows expressed on a three-phase basis corresponding to all circuits where current measurements are required." If a single phase voltage and current are collected for R6, is it acceptable to calculate power flows expressed on a 3 phase basis derived from single phase quantities? Allowing calculated power flow would prevent costly retrofits to literally provide 6 dedicated analog traces for each Element required to have a DDR. R10: The "Rationale for R10" language, "Stored data does not need to be maintained in UTC format. The data provided pursuant to a data request must be provided in UTC format with or without local time offset." Hence, requested records must be supplied in UTC format, but the collected and stored format do not. Similar to the "R3 and R6" comments above, the Requirement 10 and/or M10 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding. R10: Additionally, the "Rationale for R10" language should provide a caveat to allow for manipulating event records to UTC for equipment that is synchronized but cannot time-stamp with UTC as the reference. This would be similar to the "or derived" language suggestions to Requirements R3 and R6 which would allow for legacy equipment to meet the standard as well as allow for the time-alignment for multiple FR/SOERs as M11 evidence. Similar to the "R3 and R6" comments above, the Requirement 10 and/or M10 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding. R11: (Requirement 11.4) If relays meet the requirement of a DDR, the language of R11.1 or M11 should specify that synchrophasor data is acceptable for DDR

analysis. Relay Synchrophasor data is not compatible with the legacy COMTRADE format. R11: (Requirement 11.5) Additionally, add "Rationale for R11" language, "Collected and stored data does not need to follow the "C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME)" file naming format. The data provided pursuant to a data request must be provided in the C37.232 file naming format. Similar to the "R3 and R6" comments above, the Requirement 11.5 and/or M11 should incorporate the same language for both the Registered Entity and the auditor(s) clear understanding.
Group
ACES Standards Collaborators
Brian Van Gheem
No
We concur with the SDT's observation and rationale that "the requirement for DDR data for identified BES Elements…is based upon industry experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis." We feel that industry is not only capable of identifying the number of devices from this experience, but also where these devices should be located for dynamic disturbance recording, sequence of events recording, and fault recording purposes. We believe this standard should require an entity to generate its own methodology to make these determinations and how often. We feel the method proposed for selecting BES Elements is too broad and could be subject to interpretation from auditors when not properly followed. We also have concerns that the SDT has not identified a transition period in the standard when a Reliability Entity identifies or receives notification that they are then required to install a recording device. The only transition period the SDT has accounted for is what the SDT listed in the implementation plan and based on the effective date of the standard.
No
We disagree with the identification of BES Elements and the minimum BES Element criteria identified by the SDT. We feel that industry is capable of identifying the number of dynamic disturbance recording devices, "based upon [its] experience with wide-area disturbance analysis and the need for adequate data to facilitate event analysis." We believe this standard should require an entity to generate its own methodology to make these determinations and how often.
(1) We applaud the SDT's decision to remove the standard-only definitions provided in the previous draft revision. We also approve of the SDT's step to reduce the overall number of requirements listed in this standard. (2) However, we disagree with the SDT's claim that this standard addresses the "what" of data collected and not the "how" the data is collected. The costs of installing new equipment for the purposes of disturbance monitoring could be significant for some of our members. Moreover, industry has already benefitted from the DOE grants to install PMUs and would continue to benefit from these types of financial incentives for continual situational awareness. In its Consideration of Comments posted May 9, 2014, the SDT rebutted our previous submitted comments with references to the 2003 Blackout in the Northeast. However, it was through these financial incentives, that sufficient data was available to construct the sequence of events and other post-event analysis of disturbances for the September 8, 2011 Arizona-South California Outages. As stated within the resulting FERC-NERC Arizona-South California Outages of September 8, 2011 report generated in 2012, "PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP)." Moreover, the resulting report identified that no additional standards were necessary because of this event. We suggest NERC should develop a Reliability Guideline on this topic instead of a standard, as we do not see the cost benefit or justification to allocate resources for an issue that is not a high priority for reliability, such as cyber security. (3) We continue to have concerns that the SDT has not identified a transition period in the standard when a Reliability Entity identifies or receives notification that they are then required to install a recording device. The only transition period the SDT has accounted for is what the SDT listed in the Implementation Plan and based on the effective date of the standard. (4) We disagree with the previous response to our comments from the SDT, as cited in its Consideration of Comments posted May 9, that "to facilitate expeditious and reliable data capture, it is necessary to stipulate the data formats necessary for efficient data analysis". We feel the SDT could incorporate such stipulation in a separate technical specification or even included as reference within the standard. We feel the technical specifications listed in Requirements R8, R9, R10, and R11 would further strengthen this case, and not subject registered entities to possible

violations for every part of these requirements. We feel that technology has significantly improved since the 2003 Northeast Blackout, as manufacturers and industry have supported the need to align such devices on a common frame of time and develop related industry standards accordingly. The SDT even supports this later claim by directly referencing these standards in the text of this proposed NERC standard (see Requirement R11.4). (5) We believe numerous requirements of this Standards fall under Paragraph 81 Criteria B, and are thus unnecessary. We previously alerted the SDT to this observation and reference portions of its response, listed in its Consideration of Comments posted May 9, here. We concur with the SDT that “Disturbance Monitoring recording is necessary to ensure the reliability of the BES by providing the data for a post event analysis that can determine if system improvements are necessary to ensure reliability [and] guide real-time operating decisions.” However, we disagree that these “supportive requirements are necessary” and feel that the SDT should take some initiative. For reference, we re-list our observations below. (6) We feel Requirement R11 is arbitrary and could be subject to interpretation from auditors due to Paragraph 81 criteria. TOs and GOs could be required to prove the negative, and demonstrate that they have not received a request to provide device data to their RCs, Regional Entities, and NERC. Furthermore, this requirement meets several Paragraph 81 criteria including B1 Administrative, B2 Data Collection/Data Retention, and B4 Reporting. This requirement is administrative because it compels data formats that are immaterial to reliability with the sole purpose to simplify data collection and communication. It meets the data collection/data retention criterion because the requirement is about collecting data. It also meets the reporting criterion because it compels data reporting. We recommend the SDT should remove this requirement in its entirety. It would be more appropriate to include these specifications in a guideline. Furthermore, we feel portions of requirements R1 and R5 are “Periodic Updates” due to the need to reassess each list of affected BES Elements every five calendar years. Likewise, we feel requirements R1, R5, and R11 are “Administrative” due to the need to collect, organize, format, and then circulate data and communications sent to identified entities within a specific timeframe. We feel that several other requirements could be “Data Collection” in nature. Requirements R4.1, R4.2 require the collection of data according to specifications outlined for the minimum recording rate and data duration. Requirements R8.1 and R8.2 require the collection of data according to specifications outlined for the trigger record lengths and trigger settings. Likewise, Requirements R9.1 and R9.2 require the collection of data according to specifications outlined for input sampling rate and output recording rate. Requirement R10 requires the collection of data according to specifications outlined for time synchronization. Finally, we feel Requirement R12 is “Administrative” and “Documentation” in nature based on the need to circulate the discovery of device failure within a specific timeframe and provide a Corrective Action Plan to the Regional Entity if repair is outside this timeframe. (7) Thank you for the opportunity to comment.
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst has the following comments for consideration: 1. Requirement R6, Part 6.1.3.2 - For Requirement R6, Part 6.1.3.2 if plant that has six 200 MVA units, does this plant require any DDRs? As currently written, ReliabilityFirst believes no DDRs are required at this facility. From a monitoring perspective, ReliabilityFirst believes any plant/facility that has an aggregate nameplate greater than 1000 MVA, should have equipment capable of DDR. 2. Requirement R12, Part 6.1.3.2 - ReliabilityFirst does not understand the reasoning behind requiring the submission of the timeline for restoration and a Corrective Action Plan (CAP) to the Regional Entity. Without a requirement for the applicable entity to “implement” the CAP, the Regional Entities will have little recourse and there is little value in having the CAP if there is no requirement to complete it. Theoretically, the CAP could go on in perpetuity without completion and the entity would still be compliant, but the problem would remain unresolved. Furthermore, if the requirement requiring the applicable entity to “implement” the CAP, the Regional Entities can monitor implementation through a Regional Entity monitoring method. ReliabilityFirst recommends removing the “for submission to the Regional Entity” language and include implementation language as follows: i. “…restore the recording capability or develop a timeline with milestones for completion for restoration and implement a Corrective Action Plan (CAP).” 3. VSL for Requirement R2 - ReliabilityFirst believes the gradation of

VSLs should be in 10% increments (or similar to the VSL designations for Requirement R1). As written, if an entity only had 51% of the total SER data for circuit breaker position (open/close) for each of the circuit breakers they would only fall under the moderate VSL. ReliabilityFirst believes missing close to half of the total SER data is completely missing the intent of the requirement and should be designated as a “Severe” VSL. ReliabilityFirst has a similar comment for the VSLs associated with requirements R3, R4, R6, R7, R8 and R9.
Individual
Bob Thomas
Illinois Municipal Electric Agency
Individual
Jonathan Meyer
Idaho Power Co.
Yes
Yes
When a relay is used to capture FR data rather than a digital fault recorder, Requirement R4.1 would necessitate a relay record length of at least 32 cycles under R4.1-bullet 1 or multiple triggers under R4.1-bullet 2. Our wide variety of relay types support records of 15, 30, 60, or 180 cycles. Current practice and preference is to use a record length of 30 cycles, trigger inclusive, which was chosen to balance the amount of information in a single record while still providing the capability in the relay to save multiple records. The 32 cycle requirement would force the use of 60 cycle event records. While many of our relays are capable of this, the practice may lead to missed event records impacting our ability to search for misoperations under PRC-004. Multiple triggering has already caused events to be missed in our system due to the limited capability of some legacy relays. A change to a record length of 30 cycles including the 2 cycles of pre-fault trigger would fit within our current practice which mitigates our capture problems.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP (“ICLP”) agrees that there was no reason to keep two sets of requirements for Transmission Owners, Planning Coordinators, and Reliability Coordinators to identify DME locations, and then notify other equipment owners accordingly. The merger of the two sets of requirements makes sense to us.
No
ICLP holds to its position that the 1500 MW criteria established in CIP Version 5 for Medium-Impact generation plants is also appropriate for the placement of Dynamic Disturbance Recorders. In our view, the survey that was performed by NERC when the cyber asset bright-line criteria was developed resulted in a reasonable balance between cost and reliability benefit. There has been no corresponding justification provided under Project 2007-11 that would indicate that the 1000 MW threshold is more appropriate.
ICLP has been closely following the distribution of the Cost Effectiveness Analysis Process (CEAP) survey and its results. We agree with the general findings that the existing base of Disturbance Recorders are mostly sufficient to meet PRC-002-2’s locating and capability requirements – and that the reliability benefit of adding more equipment is minimal. However, it seems to us that NERC’s and the Regional Entities’ data analysis teams feel that the information provided in the evaluation of recent events is still lacking. This conflicts with the equipment owner’s opinions and should be reconciled. Unfortunately, the only justification seems to be that the 2003 investigation recommended the action and FERC directed it be done. This is not a minor point. The benefits of reliability oversight at the national level may be the most difficult to assess, but are the most important. Every dollar spent on compliance needs to be properly allocated, otherwise it will go to less important initiatives. As such, ICLP urges that another CEAP survey be performed – but this

time by the ERO community. Any perceived value should be quantifiable, so that it may be compared to the costs we all take on.
Group
FirstEnergy
Richard Hoag
Yes
Yes
Individual
Bill Temple
Northeast Utilities
Yes
No
The preparation and accuracy of the redlined version and this unofficial comment form is lacking and promotes confusion. The redlined version does not effectively show many of the numerous redlined changes from the last posting, including nearly all of R5. The comment form description of the changes to the implementation plan does not agree with the standard. From above description of changes: "The schedule for implementation is now to be at least 50% compliant within three (3) years following notification of the list, and 100% compliant within five (5) years following notification of the list. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be 100% compliant within five (5) years following notification of the list." From the actual standard posted for comment: Entities shall be at least 50% compliant within four (4) years of the Effective Date of PRC-002-2 and fully compliant within six (6) years of the Effective Date. Entities that own only one (1) identified BES bus location, Element, or generating unit shall be fully compliant within four (4) years of the Effective Date. Page 11, Requirement 5 states "Each Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall identify BES Elements for which dynamic disturbance recorder recording (DDR) data is required, …" While page 5 (blue explanation box& Mapping document) still states "Rationale for Functional Entities: The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the Elements for which dynamic disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those Elements selected.
Individual
David Kiguel
n/a
Yes
No
1. R5 is unclear as to whether the responsible entity needs to identify BES buses or BES Elements on which dynamic disturbance recording data would be required. 2. Part 5.1.4: It is not clear whether or not the BES Element associated with an IROL is the monitored element or the contingent element, or both. 3. The standard should not specify a number of BES elements (minimum or otherwise) for which DDR data is required. The number of Elements must be determined as those necessary to capture the necessary data to permit the complete study of key events in the BES and should not be pre-determined in the standard.
Group
Duke Energy

Michael Lowman
Yes
No
(1) Duke Energy cannot envision the reliability benefit of including relatively low ATC as a consideration for the placement of DDR equipment in bullet 5 of R5.1.2. Duke Energy suggests the following revision: “5.1.2 Any one BES Element associated with major transmission interfaces, as defined by the Responsible Entity. Selection of major transmission interfaces should consider the following guidelines: • Stability related interfaces or other significant Flowgates in the NERC Book of Flowgates for the Eastern Interconnection, or • Transfer Paths in the Western Interconnection Path Rating Catalog, or • Voltage stability limited transfer paths or load serving area, or • Interfaces between Balancing Authority Areas, or • Areas of significant congestion or thermal violation history” If an entity is calculating ATC reliably, there should not be an area of significant congestion or thermal violation history due to the inherent margins (TRM, CBM, etc.) that are built into the ATC calculation. In addition, the ATC consideration is redundant to the previous items in the same bullet.
Group
DTE Electric
Kathleen Black
Yes
Yes
Individual
Brenda Hampton
Luminant Energy Company LLC
Individual
Catherine Wesley
PJM Interconnection
No
PJM signed on the SRC’s response to this question.
No
PJM signed onto the SRC’s response to this question.
PJM urges the drafting team to reconsider including some type of alternative method for determination of the BES buses requiring sequence of events recording and fault recording as stated in the BES detailed methodology included in R1 and detailed in Attachment 1 of the standard. PJM suggested an alternative method that would be less burdensome for entities working on installation of or already have installed modern equipment with FR and SOER capabilities on their circuits. PJM appreciates the drafting team’s consideration of our proposed alternative method and understands that it is not included in the draft standard presently posted. PJM feels strongly regarding inclusion of some type of alternative method and therefore will be submitting a negative ballot for the draft standard.
Individual
Venona Greaff
Occidental Chemical Corporation
Individual
Thomas Standifur
Austin Energy
Yes

City of Austin dba Austin Energy (AE) agrees with the idea of streamlining requirements; however, as noted below in the general comments section (question 3), AE does not agree with this standard as a whole.
No
City of Austin dba Austin Energy (AE), as noted below in the general comments section, does not agree with this standard as a whole. However, AE would like to point out a few clean-up items to Requirement R5. (1) R5 includes the phrase “notify other owners of BES Elements connected to those BES buses”. “[T]hose BES buses” implies reference back to BES buses cited previously in the requirement, but they do not exist. R5 requires the Responsible Entity to identify BES Elements not BES buses. The simple fix is to strike “connected to those BES buses.” (2) AE believes R5 Part 5.2.2 would read better if the SDT changed the phrase "for each additional 3,000 MW” to “for every 3,000 MW.” Otherwise, the Responsible Entity is left asking “in addition to what?”
City of Austin dba Austin Energy (AE) does not agree with this standard as a whole. AE believes it is too prescriptive and unnecessary in the ERCOT region. Regional requirements for ERCOT regarding disturbance monitoring equipment exist in the ERCOT Nodal Operating Guides, Section 6.1. (http://www.ercot.com/mktrules/guides/noperating/cur). Existing requirements provide sufficient data for disturbance monitoring.
Individual
Jose H Escamilla
CPS Energy
Yes
No
Main issue is that “Areas of significant congestion, thermal violation history, or relatively low ATC” is very vague.
Individual
Venona Greaff
Occidental Chemical Corporation
Group
Bureau of Reclamation
Erika Doot
No
The Bureau of Reclamation suggests that the phrase “may require” in R1 and R5 should be changed to “require.” Once an element is identified as requiring data in R1 or R5, R2–R4 and R6–R10 require data collection without exception, so the phrase “may require” could create confusion.
Yes
Individual
Dianne Gordon
Puget Sound Energy
Yes
Yes
Could we use one BES location for both DDR equipment and FR/SER equipment?
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing

Wayne Johnson
Yes
Yes
a. Requirement R11, subsections 11.3, 11.4, and 11.5 do NOT have any impact on the reliability of the system. They are, in fact, entirely administrative in nature. The Results Based Standard template does not support including a requirement of these types. Efforts have been made to remove administrative-type requirements from standards. In this case, a simple mistake in formatting or when naming a file would result in non-compliance with the requirements. b. The GO requirement responsibility should be limited to making available signal sources to the adjoining TO's for the specified list of signals of interest at generating stations. In most cases the TO already owns DM equipment while the GO does not. c. We remained concerned about the cost of the needed equipment where it does already exist; but, we thank the SDT for stretching out the implementation plan which will allow the cost to be allocated over a longer period of time.
Group
Bonneville Power Administration
Andrea Jessup
No
BPA does not believe this Standard should require the Transmission Owner (TO) to notify other owners of BES equipment of their compliance responsibility. BPA also believes that other TOs (in order to determine their own compliance responsibility) should use the same fault MVA data to determine busses to which they have elements connected. BPA feels this requirement, as written, places an undue compliance risk on TOs.
No
BPA feels checks and balances need to be included to ensure Responsible Entities get concurrence from affected TOs/GOs that dynamic disturbance recording (DDR) data is needed at a given location. Additionally, an IROL is defined as in the Long-Term Planning Horizon, not in the operating horizon. BPA also believes R 5.1.5 needs clarification regarding the criteria for "major voltage sensitive area," — which is related to UVLS (for example, as represented by a metro area of 10 million people / 3000 MW). Otherwise, an isolated radial issue that doesn't impact the Interconnection may be erroneously specified.
BPA does not believe the Cost Effective Analysis Process (CEAP) uses an appropriate comparison example, without clarifying between the 2003 Interconnection wide-area, numerous-state blackout and the 2011 local-area, three-state blackout within an Interconnection, as the 2011 event would naturally take less time and data. BPA does agree, however, with the synchrophasor (PMU) data-speed impact.
Individual
Heather Rosentrater
Avista Utilities
No
Requirement R5 has the Responsible Entity (WECC RC) determining the location of Dynamic Disturbance Recorders (DDR) based on the Western Interconnection Path Rating Catalog or interfaces between Balancing Authorities (BA). WECC has never provided reasoning or justification behind the paths and the selection of the facilities included in the paths. Also the BA does not own or operate any facilities. The more appropriate entity would be the Transmission Operator to determine the interfaces in the BES.
No
Requirement R5 has the Responsible Entity (WECC RC) determining the location of Dynamic Disturbance Recorders (DDR) based on the Western Interconnection Path Rating Catalog or interfaces between Balancing Authorities (BA). WECC has never provided reasoning or justification behind the paths and the selection of the facilities included in the paths. Also the BA does not own or operate any facilities. The more appropriate entity would be the Transmission Operator to determine the interfaces in the BES.

Individual
Glenn Pressler
CPS Energy
No
Main issue is that “Areas of significant congestion, thermal violation history, or relatively low ATC” is very vague.
First issue is that we find the methodology for determining which BES busses may require SER or FR data to be overly complicated and difficult to follow. If the methodology is going to be this complicated, then perhaps the Planning Coordinator or Reliability Coordinator is best suited to perform this analysis so that Transmission Owners do not fall out of compliance for failing to understand an overly complicated spreadsheet with more than 17 steps to determine which busses require this equipment. The second issue is with the requirement of time synchronizing SER data to within +/- 2 milliseconds. While the intent of the standard appears to be to allow many modern existing relays that sample waveforms at 16 samples/cycle, have SER capabilities, and can synchronize to a GPS clock within less than 1 millisecond, this requirement will actually prohibit many of the relays because of the SER requirement. For example, a widely used SEL-311C relay can have its clocked synced to within 1 microsecond, the SER is only time-stamped once every quarter cycle, which is the processing interval of the processor. This means that the SER can only be accurate to within +/- 5 milliseconds. We think this may not be realized by the drafting team and/or many stakeholders. Additionally, we believe that the +/- 5 millisecond accuracy should be more than accurate enough if only a breaker status is required by SER. Two things to note: 1) the breaker 52a or 52b contact that would be input into the DFR device is a mechanical moving device that in and of itself may not be that accurate in regards to an actual indication as to whether the breaker is open or closed. These contacts can often be adjusted as to when they make and occasionally are even wrong in regards to status. 2) Each breaker requiring SER is in many cases already being monitored for currents that give a change of status as to the breaker being open or closed.
Individual
Daniel Duff
Liberty Electric Power, LLC
Generator owners should not be required to install DME. Generators do not model the BES, have no overall awareness of the state of the BES, and are not monitoring the overall state of the BES. The requirement should be, at most, to provide a signal showing breaker position to the TO. Requirements for GOs to provide equipment are properly the realm of the interconnection agreement, not a NERC standard, and the SDT is intruding on the contractual relationship between REs.
Individual
Laurie Williams
PNM
Yes
Yes
Suggested rewording of R12 to clearly state submission of CAP is required. “…develop a timeline for restoration and submit a Corrective Action Plan (CAP) to Regional Entity.”
Individual
D Mason
HHWP

Attachment 1, Step 7 states: "If the list has 11 or fewer BES buses: FR and SER data is required at the BES buses with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 9." It seems that word "buses" in this sentence should be changed to "bus".