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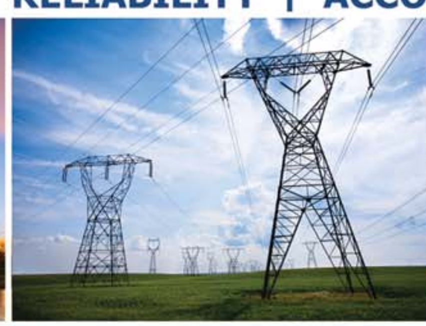
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Cost Effective Analysis Process (CEAP) Pilot For NERC Project 2007-11 — Disturbance Monitoring — PRC-002-2

CEA Phase 2 Report - Endorsed by the NERC Standards Committee

April 9,2014

RELIABILITY | ACCOUNTABILITY



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Executive Summary

The CEAP Team, consisting of an independent group of industry participants and regional entity staff, lead by a member of the Standards Committee Process Subcommittee, has rendered an opinion that the proposed standard, Disturbance Monitoring PRC-002-2- (1) provides a reasonably cost effective means for ensuring an adequate level of disturbance monitoring capability, and (2) will support the efficient and effective collection of disturbance data continent-wide on the BES.

The purpose of conducting the CEAP is to determine the relative effectiveness and cost of alternative approaches, proposed by the industry, to that of the proposed standard.

In 2013 the NERC Standards Committee approved the field test or pilot of the NERC Cost Effective Analysis Process (CEAP) (Cost Effectiveness Analysis CEA phase 2 portion), on Project 2007-11 – Disturbance Monitoring (DM). This second phase of the CEAP contains an in-depth cost assessment whose purpose is to provide detailed information to the NERC Standards Committee, Drafting Team and Stakeholders. The objective is to inform them of the relative effectiveness and cost impacts of alternative approaches to achieving the standard's reliability objective at a lower cost as compared to those proposed in the draft Reliability Standard.

The CEAP Team, NERC Staff, and the DM Standard Drafting Team appreciate the effort put forth by all commenters who submitted responses to the CEAP for Project 2007-11 – Disturbance Monitoring. The CEAP Team conducted two 30-day public comment periods to solicit estimated implementation costs and related information from the industry. The most recent CEAP comment period began on January 9, 2014 and closed on February 7, 2014. Stakeholders were asked to provide feedback on the cost of implementation of the draft standard through special electronic comment forms. There were 33 sets of comments, including comments from 80 different individuals from 39 entities representing 6 of the 10 Industry Segments.

The majority of CEA respondents believed the standard's potential immediate reliability benefits were minimal. However, most commenters agreed there was a demonstrable need to have sufficient monitoring capability available on the Bulk Electric System (BES) to record power system disturbances. The objective of such monitoring is to improve the future reliability of post-event design and operation. Some entities reported that the standard was not needed and indicated that some regional standard or criteria was already in place to assure DM capability exists on the system. The CEAP team however was unable to verify that local requirements exist on a continent wide basis.

A number of commenters also submitted potential alternative approaches concerning the placement of DM capability and the means for collecting that information. This information has been provided to the DM standard drafting team for their consideration. It is also important to understand that the standard only specifies what basic DM capability should exist and where. It does not specify any equipment requirements or describe how an entity may establish that capability.

The CEAP Team was encouraged by the amount of implementation cost estimate data submitted by the industry and the potential benefits identified both by the industry and NERC Staff. Based on this review, the CEAP Team independently, and apart from NERC staff, is of the opinion that the standard provides a reasonably cost effective means of ensuring an adequate level of disturbance monitoring capability, allowing for the efficient and effective collection of disturbance data on the BES.

Standard Type – PRC – Protection and Control
PRC-002-2 Disturbance Monitoring and Reporting Requirements

In FERC Order 693 the Commission did not approve or remand PRC-002-1. The proposed standard contained requirements that applied to the Regional Reliability Organization and did not specifically identify performance requirements for registered entities and was identified as one of 24 "fill in the blank" type standards. Project PRC-002-2 was initiated to address this concern. The approach the drafting team has taken is to specify monitoring capability rather than specify explicit types of equipment. The standard is meant only to establish what data is needed to efficiently and effectively evaluate power system disturbances, determine their root cause and develop lessons learned.

Functional Model Entity Applicability

Applicability: To Planning or Reliability Coordinators, depending on Interconnection, Transmission Owners, and Generator Owners.

Survey Participants

The CEAP Team determined a sufficient set of data points had been submitted by the industry to conduct an assessment of the results. Analysis of Participants:

a. Results from Generator Owners(GOs):

   Eighteen (18) GOs responded. An acceptable cross section of GOs responded. Among these were some of the largest entities owning generation assets.

b. Results from Transmission Owners (TOs):

   Sixteen (16) TOs responded and appears to represent an acceptable cross section of TOs. A broad spectrum of TOs responded from small to very large entities.

c. Results from Reliability Coordinators (RCs):

   Seven (7) Independent System Operators (ISO's) responded who are registered as RCs and some as Planning Coordinators (PCs). The ISO's responding represented the majority of ISO's in all the Interconnections.

Cost and Implementation Analysis

Fourteen Pilot CEA Survey Questions were posed to the industry:

T-1. How would your company capture Sequence of Events data for PRC-002-2?

T-1a. Type of equipment or whatever way your company would capture this data:

Cost to purchase,
Cost to install, and
Cost of ongoing maintenance.

T-2. How would your company capture Fault data for PRC-002-2?

T-2a. Type of equipment or whatever way your company would capture this data (for example Fault recorders, microprocessor based relays):

Cost to purchase,
Cost to install, and
Cost of ongoing maintenance.

T-3. How would your company capture Dynamic Disturbance data for PRC-002-2?

T-3a. Type of equipment or whatever way your company would capture this data:

Cost to purchase,
Cost to install, and
Cost of ongoing maintenance.

T-4. What is an approximation, in percent, of the disturbance monitoring equipment already installed, that meets the requirements of PRC-002-2 for:

T-4a. Sequence of Events Recording,
T-4b. Fault Recording, and
T-4c. Dynamic Disturbance Recording

T-5. What is the cost of purchasing and installing the equipment to capture disturbance monitoring data for your company for:

T-5a. Sequence of Events Recording,
T-5b. Fault Recording, and
T-5c. Dynamic Disturbance Recording.

CI-1. Please answer the following regarding the estimated costs and benefits of each of the proposed requirements:

CI-1a. What is the ongoing long term cost impact (after implementation) of complying with the requirements in terms of equivalent full time employees (EFTE)?
CI-1b. What are the resource benefits (labor, materials, administrative) of implementing these requirements (e.g. being able to effectively and expeditiously analyze disturbances)?

CI-2. Are there alternative method(s) or existing reliability standard requirement(s) not identified in the draft standard which may achieve the reliability objective of the standard that may result in less cost impact (implementation, maintenance, and ongoing compliance resource requirements)? If so what? Please provide as much additional supporting evidence as possible.

CI-3. How long would it take your organization to implement full compliance to the standard as written? What would affect the implementation (i.e. outage scheduling, availability of materials, human resources, etc.)?

CI-4. What NERC Functional Model registered entity or group do you will believe will benefit from this standard? (i.e. Balancing Authorities, Load-customers, etc.), and is there a value – either cost or socio-economic impact associated with that benefit? Does a NERC Functional Model registered entity or group other than the one you identified bear initial or ongoing costs related to this standard (bear a cost without receiving a benefit)?

CI-5. Do you have any other comments? If so, please provide suggested changes and rationale.

Data Analysis and Conclusions:

(For detailed redacted raw responses to the above questions which were submitted by stakeholders please refer to the Appendix of this document.)

A summary of the findings of the industry CEA Phase 2 survey is as follows:

T-1 For Sequence of Events (SOE) recording capability, a number of respondents noted there was already equipment installed on their systems of differing types, some of which were capable of performing all three of the functions and capabilities associated with SOE, Digital Fault Recorders (DFR), and Dynamic Disturbance Recorders (DDR), while at other times single use type stand alone devices were utilized. Specifically, microprocessor based devices that would have the SOE capability as required in the draft standard were cited to be in the $50K to $125K range per device, installed.

T-1a For SOE capability, the respondents identified the estimated costs of SOE monitoring devices which was averaged to be $50K - $60K (with a high of $100K to $200K) per device.
The respondents identified the estimated costs of installation of the SOE monitoring devices which was averaged to be $80K to $100K (with a high of $200K to $500K) per installation, however a number of these respondents noted that there was already sufficient SOE capability on their power system and that relatively few additional installations may be needed.
Respondents identified the estimated costs per maintenance cycle which were averaged to be $2K - $5K per installation.

T-2 For DFR capability the respondents noted a very broad range of methods to capture fault data. Phasor Measurement Unit(s) (PMU) seem to represent the preferred equipment solution to meeting the capability requirements in the standard. PMUs seem to be the most cost effective means of achieving the standard's requirements for implementing DFR capability.

T2a For DFR capability, the respondents identified the estimated costs of DFR monitoring devices which was averaged to be $50K - $60K (with a high of $120K to $400K) per device. The respondents identified the estimated costs of installation of the DFR monitoring devices which was averaged to be $50K to $60K (with a high of $120K) per installation. Respondents identified the estimated costs per maintenance cycle which were averaged to be $500 - $2K (with a high of $20K) per installation.

T-3 For DDR capability the respondents noted a very broad range of methods to capture fault data. Phasor Measurement Units (PMU) seem to represent the preferred equipment solution to meeting the capability requirements in the standard. PMUs seem to be the most cost effective means of achieving the standard's requirements for DDR capability.

T3a For DDR capability, the respondents identified the estimated costs of DDR monitoring devices which was averaged to be $50K - $60K (with a high of $100K to $200K) per device. The respondents identified the estimated costs of installation of the DDR monitoring devices which was averaged to be $50K to $60K (with a high of $200K) per installation. Respondents identified the estimated costs per maintenance cycle which were averaged to be $3K (with a high of $6K) per installation.

T-4 When the industry was asked how much equipment is already installed on the system which would meet the draft standard's requirements, the respondents noted in most cases that there was a significant amount of equipment installed and capability already in place. The range of new equipment that would be needed as a result of this standard ranged from 100% for the smaller entities to between 7 and 50 percent for the larger organizations.

T-5 Due to the ambiguity in the nature of the question, the responses did not lend themselves to a useable data point in the analysis. For example: Entities reported a variety of costs associated with individual (per unit) costs or total system costs. See Appendix for detailed responses.

CI-1a The majority of the respondents indicated a range of two (2) to three (3) equivalent Full Time Employees (FTE) to implement this standard, across the different sizes of organizations. A few have reported minimal FTE increases due to existing equipment installations or not meeting the applicability of the proposed Reliability Standard.

CI-1b The respondents, in general, agreed with the need for sufficient disturbance monitoring capability on the power system, however, some questioned the need and value of having DDR. Several respondents indicated that their respective Regions already have Disturbance Monitoring standards or requirements that appear in guides and procedures, therefore, some uncertainty exists as to the impact of this standard (i.e., requires more or less equipment). Some believe the proposed method of determining installation locations may differ from existing standards or requirements.

CI-2 Respondents indicated that alternatives to the location methodology exist. The responses will be provided to the DM SDT for further consideration. See Appendix for detailed responses.

CI-3 The majority of respondents indicated that the implementation plan was acceptable. Some of the entities noted they may need 6 to 10 years to fully implement the capability required by the draft standard. The responses will be provided to the DM SDT for further consideration. See Appendix for detailed responses.

CI-4 The consensus opinion of the respondents indicates that the reliability benefits of this standard will be of value to all functional entities.

CI-5 The responses directed at the standard or individual requirements will be provided to the DM SDT for further consideration. Responses directed at the CEAP process will be reviewed by the CEAP Team and considered during the development of future revisions to the process. See Appendix for detailed responses.

Benefit Analysis

Benefits identified during the CEAP consist, in some cases, of mitigated reliability risk statistics from the NERC Reliability Assessment and Performance Analysis (RAPA) department and/or a potential resource savings. The following was developed in collaboration with NERC's Reliability Initiatives and System Analysis department:

The benefits of having sufficient DM capability placed appropriately throughout the power system is best illustrated by the difference in the analyses of the 2003 Northeast Blackout and the 2011 Arizona-Southern California Disturbance. In 2003, NERC determined there were insufficient time-synchronized DM data in the footprint of the power system disturbance. As a result, fault records and data had to be "daisy-chained" to form a synchronized detailed sequence of events by comparing sub-second frequency, voltage, and current recordings from several disparate traces to develop time offsets between devices. The process involved several thousand traces and took five (5) subject matter experts (SME) about four (4) months to complete. Preparing graphics was virtually impossible and very time consuming. Even the rudimentary pre-dynamics period timeline took 3 months to develop.

In analysis of the 2011 event, through the use of data from 5 PMUs, the key timeline traces were completed in 2.5 hours and the sequence of events was developed by five (5) SME over a five (5) day period, including graphics of the event. The greater detail available also provided a much deeper understanding of the interacting elements of the disturbance. That is a savings of about 4,400 SME hours for the analysis.

The CEA industry responses indicated that there would be little incremental reliability benefit from the standard because entities believed that there was sufficient DM installed on the power system already. The entities did recognize the importance of being able to effectively analyze disturbances, however, believed that the standard was not needed.

Observations and Conclusions

The Survey Response observations developed by the CEAP Team follow:

- A significant portion of the DM capability already exists on the power system that satisfies the draft standard's requirements.
- Survey responses indicate that when new equipment is installed, it allows the opportunity to install multifunctional equipment that provides capability for more than one task, therefore is clearly more cost effective.
- Survey responses indicate an increase in EFTE was minimal or averaging about 2.
- The Implementation period seems to be satisfactory for those with capability already installed.
- Some entities responded that a standard was not needed in their Region, however continent wide, there may be some benefit to having a standard that identifies minimum DM capabilities and guidance to determine locations on the power system.
- No egregious costs per individual installation, which ranged typically from $100K to $160K, were identified by entities for the draft standard when considering the need and potential benefit of having sufficient equipment on the power system.
- GOs believe, in general, that there will be little reliability benefit and the costs will be difficult to recover. TOs that file tariffs and through legislation have more certain recovery through rates if costs are incurred due to implementation and future compliance with standards.

The CEAP Team, upon review of the data submitted and giving due weight to the costs vs. benefits of implementation of the standard: (a) does not opine on whether a standard is the appropriate method to address the perceived need; but (b), if it is determined that a standard is the appropriate path forward, is of the opinion that the proposed standard (1) provides a cost effective means compared to other alternatives for providing disturbance monitoring capability, and (2) will support the efficient and effective collection of disturbance data continent-wide on the BES.

The CEAP Team respectfully submits this report for informational purposes to the SC, SDT and the industry in order to better inform all stakeholders of potential costs, benefits, and impact as they develop their comments and ballot recommendations for Project 2007-11 "Disturbance Monitoring and Reporting Requirements."

CEAP Team Participants

The below listed individuals were active participants in the development of the report and opinions contained herein. In addition, there were other members who wish to remain anonymous. NERC Staff and Legal assisted with administrative tasks, posting and other supporting activities.

Chris Degraffenreid – Con Edison
Peter Heidrich – FRCC
Andy Pusztai – American Transmission Company
Steve Reukert –WECC
Kate Smith – National Grid
Guy V. Zito – NPCC – CEAP Team Lead

Appendix
Consideration of Comments

"Pilot" of the NERC CEAP regarding Project 2007-11 Disturbance Monitoring and Reporting Requirements

CEAP CEA Phase 2 PILOT- REDACTED RESPONSES (uncorrected)

T-1. How would your company capture Sequence of Events data for PRC-002-2?

A single device would cover all three applications SoE, FR, and DDR

At some locations we have a separate fault recorder and sequence of events recorder, and at other locations we have a unit that functions as both. Where there are separate pieces of equipment, we typically have the breaker indications (the required values for PRC-002-2) going to both recorders.

X would use existing microprocessor based protective relays and/or fault recorders and supplement these with several new installations.

X would use DFR and/or Relay Records to capture Sequence of Events Data.

X does not capture SOE data outside of an FR during a triggered system disturbance. Two possible options are to purchase dedicated SOE recording devices or utilize upgraded capabilities of SCADA RTUs and communications protocols. Both options would require the Company to design, purchase and install additional hardware.

Data would be captured through a combination of time synchronized digital relays, DFR's and RTU's. We do not generally install dedicated SOE recorders in our stations.

Digital Fault Recorders

Digital Fault Recorders.

X captures this data through Sequence of Event Recorders and Digital Fault Recorders.

X typically uses microprocessor relaying or digital fault recording equipment for SOE recording.

X would purchase an SER. Estimated hardware cost for the SER is $50k.

Issued from the sites, sent electronically.

Microprocessor-based (MP) Relays and Digital Fault Recorders (DFRs)

X uses a Tesla ERL to capture Sequence of Events.

Not applicable X doesn't own circuit breaker connected to the bus locations as per Requirement R2
X is required under the proposed standard to have 10 DME locations. Presently, X exceeds the required number of deployed DME locations. X would not be required to add more DME locations. X uses Qualitrol (Beta) Sequence of Event Recorders. X refers to SOEs as AMS (Alarm Management Systems).
Primary- using DFRs that also record the breaker positions in a SOER fashion. Backup- Use smart relays that record CB Positions.
Scope of SOE monitored equipment (120 kV generator breakers) unknown until TO performs analysis per Attachment 1.
See Fault Recorder section.
See R3 - If the GO owns a breaker connected to the bus locations identified by the TO (from R1 and R2), then the GO will have to apply SOE on those breakers. Estimates for installing a DME that can capture SOE, FR , and DDR range from $75k to $125k per plant.
Sequence of Events Recorders are not required by proposed Reliability Standard PRC-002-2 for X Generation's affected generation plants, because the plants do not own breakers at the Transmission Owners' bus locations.
SER, DFR and DDR data are typically captured by a single machine installed at a substation. We had standalone SER in the past but they are being removed as DFRs are being replaced in the station.
SOE data will be captured locally by a substation RTU and transmitted via EMS to the control center for alarming and logging.
There are alternatives, but our Transmission department would probably do so through the use of digital transient recorders (DTR) with SER capability. For our Generation department we would install a new digital fault recorder (DFR) at X, Y, and Z and use the existing SEL relays with UTC time from satellites at our other sites.
Through the use of microprocessor relays synchronized through a GPS satellite clock monitoring status of elements.
Use microprocessor-based protective relays
We will be capturing SOE data in microprocessor relays only.
We would capture SOE data through the use of a state of the art modern DME box.

T-1a. Type of equipment or whatever way your company would capture this data: Cost to purchase: Cost to install: Cost of ongoing maintenance:

$190,000. $95,000. $4,000 annually.

(1) Cost to purchase: $100,000 - $200,000 per installation(2) Cost to install: $200,000 per installation(3) Cost of ongoing maintenance: $3000/maintenance cycle per installation

(1) Our current plan is to use channels of the fault records at these locations. The cost is included in T-2. (2) Our understanding of PRC-002-2 Draft 2 requires only breakers' auxiliary contact at the FR locations.

An estimated total cost for planning, engineering, procurement, construction, startup, comissioning, and outages would be approximately $400,000 per site. There are 38 sites which have tentatively been identified to meet this criteria, a percentage of which already have a DME box. At some of these sites the same equipment will be used for recording sequence of events, faults and dynamic disturbances (T-1a, T-2a and T3a). Note: This estimate is within +/- 50% and is to be used for planning purposes only.

Cost to Purcahse/Type of Equipment: We have not determined a final cost figure at this time. Although we have not figured out exactly where we would need to install DME per PRC-002-2, nearly all of our EHV (345kV and up) lines and 2/3rds of our 138kV lines already have microprocessor relays. We are additionally planning a large number of 138kV line upgrades over the next five years to convert audiotone circuits and some carrier circuits to fiber. We are not upgrading relays on our autotransformers at such a high rate as they do not need the modern relays to improve reliability to anywhere near the extent that lines do and transformer relays are not a constant maintenance headache as line communication circuits can be. We've commented to the drafting team that their process should be such that a system that is so heavily monitored should not be penalized to have to install SOE on transformers to get to 20% when 100% of EHV lines are monitored. So we are optimistic that the standard drafting team will agree that this is technically accurate and we will not need to purchase any additional relays to capture SOE data as this installed base provides a huge amount of data coverage. Cost to Cost to Install: Undetermined at this time, see cost to Purchase. Cost of ongoing maintenance: Since the microprocessor relays that we will be using to provide SOE data also provide line protection and maintenance is already required per PRC-005, there would be no additional testing or ongoing maintenance required for these devices.

Cost to purchase and install $50,000 - $60,000Annual Maintenance costs $2,000 per site (we currently have 12 sites where we've already installed the Tesla, and would need to install 1 more to be compliant with PRC-002).

Cost to purchase: MP Relay: $5000 per device DFR: $40,000 per device Cost to install: MP Relay: $35,000 per device DFR: $35,000 per device Cost of ongoing maintenance: MP Relay: $2,000 per device every 10 years DFR: $3,000 per device per year

Cost to purchase: Approximately $50K-$100K per installation, up to 5 installations Cost to install: Approximately $200K-$500K per installation, up to 5 installations Cost of ongoing maintenance: Negligible

Cost to purchase: DFRs ~ $96,000Cost to install: DFRs ~ $35,000Cost of ongoing maintenance: ~ $3,000 annually
Cost to purchase: minimal, mostly existing equipment Cost to install: minimal, mostly existing equipment Cost of ongoing maintenance: NA
Cost to purchase: $50,000 Cost to install: $55,000Cost of ongoing maintenance: $7,500 per year for the entire population.
Cost to purchase: $98,000Cost to install: $101,000 Cost of ongoing maintenance: $500 annually
Cost to purchase: 0$Cost to install: 0$Cost of ongoing maintenance: 0$
Cost to purchase: 20K per DFR, Typical substation 3-4 DFR's Cost to install: 40K per DFR, Typical Substation 3-4 DFR’s Cost of ongoing maintenance: minimal to none
Estimated installation cost of $50k. $2000 every three years. We network connect our SER units and automatically retrieve the event data daily.
In most cases (all cases applicable to PRC-002), an RTU is already installed to provide this functionality. Installation of a new RTU at a facility is expected to cost on the order of $100,000.Cost to purchase: $20,000Cost to install: $80,000Cost of ongoing maintenance: $5,000/year
Microprocessor relays and GPS clock cost approx. $120,000 to purchase: approx. $120,000 to install: approx. $20,000 every 5 years for testing and/or maint. and $10,000 every year for ongoing monthly inspection of equipment.
No comment.
X uses Qualitrol (Beta) Sequence of Event Recorders. X refers to SOEs as AMS (Alarm Management Systems).Cost to purchase: see below Cost to install: For a stand alone AMS, cost to purchase and install is approximately $400K. For an AMS and DFR concurrent installation, cost is approximately $525K. For a NNGS SOE installation, cost is approximately $70K.Cost of ongoing maintenance: n/a
PRC-002-2 data would be captured in a digital fault recorder that could also do Sequence of Events capture of breaker position.
Purchase : ~ $35,000 per DTR   ~ $25,000 per DFR Install :   ~ $20,000 per DTR   ~ $10,000 per DFROngoing Maintenance: ~ $4,000 annually per DTR   ~$2,000 annually per unit for all sites
Several SER types now in service.
This equipment is existing so there is no additional cost to install or maintain this equipment for purposes of PRC-002-2.

Total installed cost: $150-200KCost of ongoing maintenance: $1K annually

Type of equipment or whatever way your company would capture this data: DFRs w/SER capability Cost to purchase: $40000 This is a total for SER & DFR data for a small station (1 bus). Large station is $85000 (2-3 busses) Cost to install: $20000 This is a total for SER & DFR data for a small station (1 bus). Large station is $40000 (2-3 busses) Cost of ongoing maintenance: Did not fully understand intent of questions ince this is a data standard. Assume that SDT is interested in follow up operation and maintenance after installed to understand future financial impacts. $4000/year per installation

Use SOE functionality of Digital Fault Recorders, and perhaps IED relays. Cost to purchase: Included with Fault Recorder Cost to install: Included with Fault Recorder Cost of ongoing maintenance: Included with Fault Recorder

T-2. How would your company capture Fault data for PRC-002-2?

A combination of microprocessor relays ($15k each) or a station digital fault recorder ($50k equipment cost)

A single device would cover all three applications SoE, FR, and DDR

Appears to be no additional Fault monitoring required.

X would use existing microprocessor based protective relays and/or fault recorders and supplement these with several new installations.

X would use the same equipment listed in T-1; DFR and/or Relay Records to capture Fault data as well.

X will capture fault data using existing installed DFRs. X anticipates that it will have to purchase and install approximately two (2) additional DFRs based upon the draft Standard and Attachment 1 methodology.

Digital Fault Recorders

Digital Fault Recorders.

X captures this data through Sequence of Event Recorders and Digital Fault Recorders.

Fault data would be captured by standalone DFRs. Typically all line currents and voltages are recorded including Auto Transformers.Note: for breaker and a half schemes, each line has its currents and voltages monitored separately.

Fault Recorders are not required by PRC-002-2 for X Generation’s affected generation plants, because the plants do not own breakers at the Transmission Owners’ bus locations.

X typically uses microprocessor relaying or digital fault recording equipment for capturing fault data.

Issued from the sites; sent electronically.
X would continue to use ERL Tesla's to capture fault data for PRC-002-2.
MP Relays and DFRs
Not applicable X doesn’t own transmission line neither transformers that have a low-side operating voltage of 100kV or above.
X uses Mehta Tech IED DFRs for installation to capture fault data.
Primary - Using DFRs that record oscillography for each Element. Will install additional DFRs as/if needed.
Same as T-1, see above
See R4 - If the GO owns a the bus identified by the TO (from R1 and R2), then the GO will have to apply FR on the bus.
Substation digital relays will record oscillography during the event. Oscillography files will be automatically retrieved and date/time-stamped via an SEL software package that accesses the data via a wide-area substation Ethernet connection and port switch.We do not have any plans to install additional DFRs for fault data capture.
There are alternatives, but our Transmission department would probably do so through the use of DTRs. Our Generation department would install DFRs at X, Y, and Z and use the newly installed SEL relays at the other sites.
This equipment is existing so there is no additional cost to install or maintain this equipment for purposes of PRC-002-2.
Use a combination of automatic reporting to a master station, remote dial-up, and site visits as necessary.
We will be capturing Fault data in microprocessor relays only.
We would capture fault data through the use of a state of the art modern DME box.
We would use microprocessor relays with inputs from current and voltage sensing devices in the substations to capture and store fault data electronically in the relay.

T-2a. Type of equipment or whatever way your company would capture this data (for example Fault recorders, microprocessor based relays): Cost to purchase: Cost to install: Cost of ongoing maintenance:

$70,000. $40,000. $3,200 annually.
(1) Cost to purchase: $100,000 - $200,000 per installation(2) Cost to install: $200,000 per installation(3) Cost of ongoing maintenance: $3000/maintenance cycle per installation
(1) In almost all cases we plan to use a fault recorder. (2) Most of our FR locations are already in our NERC DME program in accordance with Regional Criteria. (3) For today's system, R1 method yields 35 locations, which causes us to add 5 more locations. (4) Four of the five locations are between locations that are already monitored but make the top fault MVA list; in our view this isn't cost effective. We have estimated the total installed cost at up to $275k.
A DFR installation would be estimated at $50k. Relay installation is estimated at $95k. A relay would not be installed solely for fault recording but more likely as an upgrade or replacement of an existing protection system. Therefore, the higher cost reflects the removal and replacmenet of the old protection system with the new. $2000 every three years.
An estimated total cost for planning, engineering, procurement, construction, startup, comissioning, and outages would be approximately $400,000 per site. There are 38 sites which have tentatively been identified to meet this criteria, a percentage of which already have a DME box. At some of these sites the same equipment will be used for recording sequence of events, faults and dynamic disturbances (T-1a, T-2a and T3a). Note: This estimate is within +/- 50% and is to be used for planning purposes only.
Cost to purchase and install $50,000 - $60,000Annual Maintenance costs $2,000 per site (we currently have 12 sites with a Tesla, and would need to install 1 more to be compliant with PRC-002).
Cost to purchase: Covered by same equipment and cost as T-1 Cost to install: Covered by same equipment and cost as T-1Cost of ongoing maintenance: Negligible
Cost to purchase: $16,000 (138-kV digital relay panel)Cost to install: $64,000Cost of ongoing maintenance: $5,000/year
Cost to purchase: 0$Cost to install: 0$Cost of ongoing maintenance: 0$
Cost to purchase: 20K per DFR, Typical substation 3-4 DFR's Cost to install: 40K per DFR, Typical Substation 3-4 DFR's Cost of ongoing maintenance: minimal to none
Cost to purchase: DFRs ~ $96,000Cost to install: DFRs ~ $35,000Cost of ongoing maintenance: ~ $3,000 annualy
Cost to purchase: MP Relay: $5000 per device; DFR: $40,000 per device Cost to install: MP Relay: $35,000 per

device; DFR: \$35,000 per device Cost of ongoing maintenance: MP Relay: \$2,000 per device every 10 years; DFR: \$3,000 per device per year
Cost to purchase: see below Cost to install: For a stand alone DFR, cost to purchase and install is approximately \$275K. For an AMS and DFR concurrent installation, cost is approximately \$525K. For a NNGS DFR, SEL400 series relays connected to EU NET; cost of purchase and installation is approximately \$30K per substation. Cost of ongoing maintenance: n/a
Cost to purchase: Undetermined at this time: Although we have not figured out exactly where we would need to install DME per PRC-002-2, nearly all of our EHV (345kV and up) lines and 2/3rds of our 138kV lines already have microprocessor relays. We are additionally planning a large number of 138kV line upgrades over the next five years. We are not upgrading relays on our autotransformers at such a high rate as they do not need the modern relays to improve reliability to anywhere near the extent that lines do. We've commented to the drafting team that their process should be such that a system that is so heavily monitored should not be penalized to have to install fault recording on transformers to get to 20% when 100% of EHV lines are monitored. This will come over time on its own. So we are optimistic that the standard drafting team will agree that this is technically accurate and we will not need to purchase any additional relays to capture fault recording data as this installed base provides a huge amount of data coverage. Cost to install: See above. Undetermined at this time. Cost of ongoing maintenance: Since the microprocessor relays that we will be using to provide fault recording data also provide line protection and maintenance is already required per PRC-005, there would be no additional testing or ongoing maintenance required for these devices.
Dedicated DFR equipment. Cost to purchase: Approximately \$400,000 Cost to install: Approximately \$100,000 Cost of ongoing maintenance: Approximately \$10,000
DFR - Typical substation installation covering 128 Analogs and 224 Event channels is priced here. Cost to purchase: \$98,000 Cost to install: \$101,000Cost of ongoing maintenance: \$500 Annually
Digital Fault Recorders (DFR) Cost to purchase: \$50,000Cost to install: \$55,000
Fault recorders would be used to capture this data. Cost to purchase: Would need to replace 1 fault recorder = \$110,000Cost to install: \$7,000Cost of ongoing maintenance: \$2000 for one replaced recorder. \$30,000 for ongoing maintenance of all required fault recorders
Fault Recorders Cost to purchase: \$4.7M Cost to install: \$7.5M Cost of ongoing maintenance: \$80K
Microprocessor relays and GPS clock cost approx. \$120,000 to purchase: approx. \$120,000 to install: approx. \$20,000 every 5 years for testing and/or maint. and \$10,000 every year for ongoing monthly inspection of equipment. These are the same costs used in T-1a.
No comment.
Purchase: ~ \$35,000 per DTR ~ \$25,000 per DFRInstall: ~ \$20,000 per DTR ~ \$10,000 per DFR Ongoing

Maintenance: ~ $4,000 annually per DTR ~$2,000 annually per unit for all sites
Several types in service.
Total installed cost: $150-200KCost of ongoing maintenance: $1K annually
Type of equipment or whatever way your company would capture this data (for example Fault recorders, microprocessor based relays): DFRs primary and smart relays will be used as backup. Cost to purchase: Included in SER hardware used in T1 question Cost to install: Included in SER hardware used in T1 question Cost of ongoing maintenance: Included in SER hardware used in T1 question
We use Digital Fault Recorders due to the storage limitations of microprocessor relays.Cost to purchase: 2 additional locations have been identified as needing DFR to comply with the draft standard as written. The cost to purchase and install DFR at each location is approximately $250,000 or $500,000 total cost. Cost to install: See Above Cost of ongoing maintenance: $1,250/year per DFR, or $2.500 per year total given the addition of 2 DFR's to comply with the standard.

T-3. How would your company capture Dynamic Disturbance data for PRC-002-2?

A combination of digital fault recorders and phasor measurement units (PMU).
A single device would cover all three applications SoE, FR, and DDR
X would use existing microprocessor based protective relays and/or fault recorders and supplement these with several new installations.
X would use PMU's to capture Dynamic Disturbance Data.
X does not capture dynamic disturbance data at this time.
DFRs
Digital Fault Recorders
Digital Fault Recorders
X captures this data through Sequence of Event Recorders and Digital Fault Recorders.
Dynamic Disturbance data would be captured by solid state DDR devices, with manual downloading when records have been requested by the entities listed in proposed Requirement R.13.
X relies on an installation of a DFR that includes DDR capability. The microprocessor relaying use for SOE and DFR are not relied upon for DDR.

Issued from the sites; sent electronically.
X would continue to use ERL Teslas to capture Dynamic Disturbance data for PRC-002-2.
Nineteen PMUs are presently installed on X’s 345-kV system. As defined, a PMU-capable digital relay will meet the DDR requirements.
Not applicable X doesn’t own location and Element for which Dynamic Disturbance Recording (DDR) is required as established in Requirement R6.
Plan to use phasor-measurement units (PMUs)
Power swings, frequency variations, and abnormal voltage problems would be captured through the use of current and voltage sensing devices wired to microprocessor based relays.
X uses Mehta Tech IED DFRs; it also can capture Dynamic Disturbance data.
Primary- using continuous RMS and phase data using DFRs. Backup- A backup device would be protective relays that stream PMU data to data concentrator and stored locally.
Remote dial-up and/or data continuously sent to a centralized server.
Solid state DDR device, with manual downloading (generation plant) when records have been requested by other entities - use either GO owned or TO owned equipment (with a contract between GO TO for use of their equipment)Remote dial in capability would be very beneficial.
There are alternatives, but our Transmission department would probably do so through the use of DTRs with disturbance monitoring capability. For our Generation department we would install a DFR at X,Y, and Z. We would not capture this at the other sites.
This data would be captured through the use of a dedicated Dynamic Disturbance Recorder.
Type of equipment not fully determined at this time.
Typically we capture all three types of data with our DFRs; however, we also have used PMUs, which meet the DDR requirements as well.
Use fault recorders that can also capture dynamic disturbance data for PRC-002-2.
We will use relays to act as Phasor Measurement Units and send the data to Phasor Data Concentrators to be stored as Dynamic Disturbance Data in most cases, in a few we’re storing data locally.
We would capture dynamic disturbance data through the use of a state of the art modern DME box.

T-3a. Type of equipment or whatever way your company would capture this data: Cost to purchase: Cost to install: Cost of ongoing maintenance:

$630,000. $360,000. $28,800 annually.

(1) Cost to purchase: $100,000 - $200,000 per installation(2) Cost to install: $200,000 per installation(3) Cost of ongoing maintenance: $3000/maintenance cycle per installation

(1) This cost is somewhat dependent on location, as greater costs would be incurred for any location not presently having sufficient network communications bandwidth to support the data transmission requirements. (2) Based on experience gained through participation in the X Synchrophasor project, our estimated installed cost estimate is up to $ 9 million. (3) The vast majority of these are caused by R6.1.4 flowgates, which in our view are not technically justified. Flowgates monitor flow conditions with respect to thermal limits in our system. Flowgates are unrelated to stability. (4) As we commented on draft 2, R6.1.4 is unsubstantiated and a primary reason for our negative ballot; the other sections of R6 already triple the number of required DDR. (5) In our opinion R6.1.4 is not cost effective. We believe that the implementation schedule of 4 years may force base load units off-line in order to comply, which could incur a cost of several million dollars.(6) Cost of ongoing maintenance: Our total cost of maintenance is estimated at $43,000 annually, including R14 maintenance and licensing fees.

An estimated total cost for planning, engineering, procurement, construction, startup, comissioning, and outages would be approximately $400,000 per site. There are 27 sites which have tentatively been identified to meet this criteria, a percentage of which already have a DME box. At some of these sites the same equipment will be used for recording sequence of events, faults and dynamic disturbances (T-1a, T-2a and T3a). Note: This estimate is within +/- 50% and is to be used for planning purposes only.

Available options will need to be evaluated. The cost is unknown due to the uncertainty of the type of equipment and number and location of required DDR units.

DDR would be purchased in a turnkey fashion, not as separate equipment and installation contracts. 1) The expected total installed cost is approximately $125,000-140,000 for a plant requiring new DME. 2) The expected total installed cost is approximately $25,000-30,000 for any plants at which existing SOER and FR would be converted to DDR. 3) Other plants have existing SOER and FR equipment. 5) For X's nuclear plant(s), the additional engineering costs can run hundreds of thousands of dollars, possibly up to a million dollars. Minimal ongoing maintenance costs, assuming maintenance similar to that for solid-state protective relays (i.e. every six years) and need to manually download captured events only rarely.

Cost to purchase and install $50,000 - $60,000Annual Maintenance costs $2,000 per site (we currently have 12 sites with a Tesla, and would need to install 1 more to be compliant with PRC-002).

Cost to purchase: Approximately $15K-$100K per installation, up to 20 installations Cost to install: Approximately $75K-$500K per installation, up to 20 installations Cost of ongoing maintenance: Negligible

Cost to purchase: $10,000 (assuming PMU-capable relay is existing)Cost to install: $10,000Cost of ongoing maintenance: $2,000/year
Cost to purchase: $40,000 per deviceCost to install: $35,000 per deviceCost of ongoing maintenance: $3,000 per device per year
Cost to purchase: 0$Cost to install: 0$Cost of ongoing maintenance: 0$
Cost to purchase: 22k per unit Cost to install: 66k to install and engineer per unit Cost of ongoing maintenance: minimal to none
Cost to purchase: DFRs ~ $96,000Cost to install: DFRs ~ $35,000Cost of ongoing maintenance: ~ $3,000 annualy
Cost to purchase: For our company, there are two requirements in hte standrd that could cause us to spend a considerable amount of money on DDR equipment. The worst is 6.1.4 (monitoring of all permanent flowgates), the other is monitoring of all elements of an IROL. Our company already has stored synchrophasor data on all of our largest units and more DDR locations than one per 3000MW of peak load (probably one per 1500MW of peak load). Our RC/TP has created an IROL for our company that consists of every tie line 138kV and above or about 32 lines. Many of these lines are not critical. Our RC/TP has categorized 51 138kV and above lines as parts of flowgates. There is some overlap between the two lists and we could perhaps take credit for some coverage of our existing installed stored synchrophasors and some by our neighbors. If we estimate we would need to install 50 additional PMUs along with all the infrastructure to communicate this data back to a central storage location (of which we would have to figure out a design), a rough estimate for purchase cost is $15k per PMU or $750k total.   Cost to install: Installation costs are typically 3 to 4 times purchase costs. If we use 3, the estimated cost to install would be $2,250,000. Such a project would take many years to install.Cost of ongoing maintenance: It is difficult to figure out a maintenance cost for such a large PMU/PDC system. Relays are already maintained because they also provide protection but relays are a small part of the infrastructure of a synchrophasor data collection system. A guess to maintain such a system including troubleshooting problems with communications, etc. would be at least $100k per year.
Cost to purchase: see below Cost to install: For a stand alone DFR, cost to purchase and install is approximately $275K. For an AMS and DFR concurrent installation, cost is approximately $525K.Cost of ongoing maintenance: n/a
Cost to purchase:$50,000Cost to install:$55,000
Cost to purchase:The total installed cost of a single DDR (based on a recent installation) is $161,000. To comply with this standard, an estimate of an additional 50 DDR must be installed in X territory per our Reliability Coordinator. This dictates a total installed cost of $8,050,000.   Cost to install: See Above Cost of ongoing maintenance: Same as a DFR, $1,250/year per DDR, for a total additional maintenance cost of $62,500/year for the 50 additional DDR.
DFR installation already estimated at $50k plus hardware. A PMU installation is estimated similarly at $50k

plus hardware. $2000 every three years.

DFRs/Relays Cost to purchase: $40000 /installation (apply online if DFR/SER is not already installed) Cost to install: $20000/installation Cost of ongoing maintenance: $3000/yr per installation

DME that can capture SOE, FR, and DDR. Minimal for generation plants, assuming maintenance similar to that for solid-state protective relays (i.e. every six years) and need to manually download captured events only rarely. An estimate for each generating facility is $100k per plant (given previously in question T1).

Fault Recorders Cost to purchase: Would need to upgrade 5 fault recorders to have Dynamic Disturbance capture capabilities. Approx. $90,000 each = $450,000. 2 of these were already listed under the Sequence of events section, so the net total would be $270,000Cost to install: $7000 x 5 = $35,000. Net cost (minus the 2 mentioned earlier) = $21,000.Cost of ongoing maintenance: $16,000 for all required Dynamic Disturbance Recorders. (Would be covered under fault recorder maintenance)

If we installed a stand alone DDR recorder we would utilize a protection relay that provides PMU/DDR capabilities. The system would cover 4 transmission lines. Cost for such a system is considered below. Cost to purchase: $85,000Cost to install: $65,000Cost of ongoing maintenance: Due primarily to cost of the data circuit $6,400 Annually

Microprocessor relays $120,000 to purchase: approx. $120,000 to install: approx. $20,000 every 5 years for testing and/or maint. and $10,000 every year for ongoing monthly inspection of equipment. The current and voltage sensing devices are currently installed at locations that could be affected by this standard.

PMUs, associated phasor data concentrators, communication equipment, and software $ 200,000; $ 75,000; $ 5,000 per year

Purchase: ~ $35,000 per DTR ~ $25,000 per DFRInstall: ~ $20,000 per DTR ~ $10,000 per DFR Ongoing Maintenance: ~ $4,000 annually per DTR ~ $2,000 annually per unit for all sites

Total installed cost: $150-200KCost of ongoing maintenance: $1K annually

Typically use Fault Recorders upgraded with DDR continuous recording capability at locations where Fault Recorders are also required. Alternatively, consider using PMUs at required locations where a Fault Recorder may not be required. Cost to purchase: $20M Cost to install: $20M Cost of ongoing maintenance: $200K

T-4. What is an approximation, in percent, of the disturbance monitoring equipment already installed, that meets the requirements of PRC-002-2 for: T-4a. Sequence of Events Recording: T-4b. Fault Recording: T-4c. Dynamic Disturbance Recording:

T-4a. Sequence of Events Recording: 100% T-4b. Fault Recording: 100% T-4c. Dynamic Disturbance Recording: 100%

0%: 0%: 0%. This requirement is not applicable to X today but with the 1500 MVA short circuit limit, one location could become applicable when this standard is implemented.
86%. 100%. 25%.
90; 90; 0
a. 95%b. 50% (100% at the cricitical stations)c. 10%
Depends on final standard language? T-4a. Sequence of Events Recording: 85% T-4b. Fault Recording: 85% T-4c. Dynamic Disturbance Recording: 70%
Not applicable X doesn't own - circuit breaker connected to the bus locations as per Requirement R2- transmission line - transformer that have a low-side operating voltage of 100kV or above- location and Elements for which Dynamic Disturbance Recording (DDR) is required as established in Requirement R6.
T-4a X has done a pilot review for 3 of X operating companies and based on this review, we do not anticipate a large burden to implement the NERC PRC-002-2 standard. At this time, in those 3 operating companies, we believe we have 100% of the installations covered with existing equipment. We believe the remaining 7 operating company areas will have approximately 90% of the installations covered with existing equipment. X is well positioned for the PRC-002-2 standard based on a prior implementation of X criteria for DME installations.T-4b Fault Recording: See response to T-4aT-4c Dynamic Disturbance Recording: See response to T-4a
T-4a) Sequence of Events Recording: Not required by PRC-002-2 for our generation plants, as noted above. T-4b) Fault Recording: Not required by PRC-002-2 for our generation plants, as noted above. T-4c) Dynamic Disturbance Recording: X currently has no DDR equipment installed at its plants. Three of its X plants currently have SOER and FR equipment that should be able to be converted to DDR service.
T-4a. Sequence of Events Recording: 99%T-4b. Fault Recording: 95%T-4c. Dynamic Disturbance Recording: 38%
T-4a. Sequence of Events Recording: About 86%T-4b. Fault Recording: About 86%T-4c. Dynamic Disturbance Recording: We currently have 3 NERC required locations and combined with another project we have installed 38 total phasor measurement units on the X system would meet requirements for the proposed PRC-002-2 as drafted. Assuming they align with the 180 locations that PRC-002-2 appears to us to require, then we have about 20% already installed.
T-4a. Sequence of Events Recording: 0%T-4b. Fault Recording: 0%T-4c. Dynamic Disturbance Recording: 0%
T-4a. Sequence of Events Recording: 100%T-4b. Fault Recording: 100%, 80% digital relays, plus remainder covered by DFRT-4c. Dynamic Disturbance Recording: Depends on RE requirements, although we feel we are in a good position today.

T-4a. Sequence of Events Recording: 100%T-4b. Fault Recording: 100%T-4c. Dynamic Disturbance Recording: 90%
T-4a. Sequence of Events Recording: 22 to 55%T-4b. Fault Recording: 22 to 55%T-4c. Dynamic Disturbance Recording: 0%
T-4a. Sequence of Events Recording: 40%T-4b. Fault Recording: 40%T-4c. Dynamic Disturbance Recording: 40%
T-4a. Sequence of Events Recording: 80%; T-4b. Fault Recording: 80%; T-4c. Dynamic Disturbance Recording:45%
T-4a. Sequence of Events Recording: 83% already installed within X T-4b. Fault Recording: 83% already installed within X T-4c. Dynamic Disturbance Recording: 77% already installed within X
T-4a. Sequence of Events Recording: 90%T-4b. Fault Recording: 90%T-4c. Dynamic Disturbance Recording: 75%
T-4a. Sequence of Events Recording: Included with Fault Recorders T-4b. Fault Recording: 45% T-4c. Dynamic Disturbance Recording: 2%
T-4a. Sequence of Events Recording: See answer to T-1.T-4b. Fault Recording: See answer to T-2.T-4c. Dynamic Disturbance Recording: See answer to T-3.
T-4a. Sequence of Events Recording: 50%T-4b. Fault Recording: 50%T-4c. Dynamic Disturbance Recording:0%
T-4a. Sequence of Events Recording: It is estimatmated that 100% of presently installed equipment meets the technical requirements of PRC-002-2T-4b. Fault Recording: It is estimatmated that 100% of presently installed equipment meets the technical requirements of PRC-002-2T-4c. Dynamic Disturbance Recording:It is estimatmated that 100% of presently installed equipment meets the technical requirements of PRC-002-2
T-4a. Not currently intalled T-4b. Approximately 90% T-4c. Not currently installed
T-4a. Sequence of Events Recording: 85%T-4b. Fault Recording: 92%T-4c. Dynamic Disturbance Recording: 25%
T-4a: 75%T-4b: 95%T-4c: 85%
Unknown until TO determines locations .N/A10%
We currently have 12 out of 13 sites where disturbance monitoring equipment has already been installed (Approximately 93% complete).

T-5. What is the cost of purchasing and installing the equipment to capture disturbance moitoring data for your company for: T-5a. Sequence of Events Recording: T-5b. Fault Recording: T-5c. Dynamic Disturbance Recording:

T-5a. Sequence of Events Recording: Included with Fault Recorders T-5b. Fault Recording: $12.2M T-5c. Dynamic Disturbance Recording: $40.0M

$240,000: $240,000: $240,000

$285,000. $110,000. $990,000.

(1) Cost to purchase: $100,000 - $200,000 per installation(2) Cost to install: $200,000 per installation(3) Cost of ongoing maintenance: $3000/maintenance cycle per installation

(1) If the SDT intended the sum of items T-1, T-2, and T-3, then please sum them; this total could reach $11.5 million. (2) If the SDT intended the cost of data communication and centralized storage to satisfy the R13 data availability requirements, then see below.T-5a. Sequence of Events Recording: Included with FR.T-5b. Fault Recording: We request clarification as to the intent of R13 data retrievability for 10 days to us this is unclear. We believe that an unreasonable reading could force continuous FR data recording and/or central data storage. If that's the SDT's intent, we estimate another $450k incremental installed cost impact at existing FR locations.T-5c. Dynamic Disturbance Recording: Upgrade of our data concentrator causes another $38,000.

a. The cost to our Transmission department is unknown at this time. Our Generation department approximates it at $5,000 for satellite clocks at some locations.b. The cost to X is unknown at this time.c. The cost to our Transmission department is unknown at this time. Our Generation department estimates this at $25,000 per unit.

Confusing question.. is this asking for total cost assuming no equipment installed today or additional cost to install additional DME per new requirements, or does it refer to having communication infrastructure to auto download capture data? T-5a. Sequence of Events Recording: T-5b. Fault Recording: T-5c. Dynamic Disturbance Recording:

Cost to complete installation of the necessary equipment to meet PRC-002 as it stands today.T-5a. Sequence of Events Recording:T-5b. Fault Recording: Total all additional equipment $5,000,000T-5c. Dynamic Disturbance Recording:

Cost to purchase and install $50,000 - $60,000Annual Maintenance costs $2,000 per site (we currently have 12 sites with a Tesla, and would need to install 1 more to be compliant with PRC-002).

minimal; minimal; $ 275,000

Not applicable to X T-5a. Sequence of Events Recording: 0$T-5b. Fault Recording: 0$T-5c. Dynamic Disturbance Recording: 0$

T-5a) Sequence of Events Recording: Not required by PRC-002-2 for our generation plants, as noted above. T-5b) Fault Recording: Not required by PRC-002-2 for our generation plants, as noted above. T-5c) Dynamic Disturbance Recording: See responses to question T-3a above.
T-5a. Sequence of Events Recording: ~ $700,000 T-5b. Fault Recording: Included in above.T-5c. Dynamic Disturbance Recording: Included in above.
T-5a. Sequence of Events Recording: Refer to T-1T-5b. Fault Recording: Refer to T-2T-5c. Dynamic Disturbance Recording: Refer to T-3
T-5a. Sequence of Events Recording: $0T-5b. Fault Recording: $0T-5c. Dynamic Disturbance Recording: $300-500K
T-5a. Sequence of Events Recording: $0T-5b. Fault Recording: 2 locations at $250,000 each = $500,000T-5c. Dynamic Disturbance Recording:50 locations at $161,000 per location = $8,050,000.
T-5a. Sequence of Events Recording: 38 sites @ $400k @20% of sites = $3M; T-5b. Fault Recording: 38 sites @ $400k @20% of sites = $3M; T-5c. Dynamic Disturbance Recording: 27 sites @ $400k @55% of sites = $5.9M. At some of these sites the same equipment will be used for recording sequence of events, faults and dynamic disturbances (T-5a, T-5b, and T-5c), so the total $11.9M is a worst case estimate. Note: This estimate is within +/- 50% and to be used for planning purposes only.
T-5a. Sequence of Events Recording: 60k per DFR, 3-4 DFR’s per substation- approximately 2 substations = 480K T-5b. Fault Recording: included in above cost because same equipment is used. T-5c. Dynamic Disturbance Recording: 88k per location- approximately 5 locations= 440k
T-5a. Sequence of Events Recording: Assuming this question seeks the total cost for purchasing and installing SOER equipment under this proposed standard, we would need to know the required locations which have not been identified. T-5b. Fault Recording: Assuming this question seeks the total cost for purchasing and installing FR equipment under this proposed standard, we would need to know the required locations which have not been identified.T-5c. Dynamic Disturbance Recording: Assuming this question seeks the total cost for purchasing and installing DDR equipment under this proposed standard, we would need to know the required locations which have not been identified.
T-5a. Sequence of Events Recording: Cost of EMS and PI/e DNA storage systems are prohibitive ($10M+)T-5b. Fault Recording: SEL-5045 data retrieval application costs $100 per device license (estimate $100,000 to address 900 devices at PRC-002 facilities)T-5c. Dynamic Disturbance Recording: Phasor Data Concentrator (PDC) costs are on the order of $200,000 for a system that communicates with up to 50 PMUs
T-5a. Sequence of Events Recording: T-5b. Fault Recording: T-5c. Dynamic Disturbance Recording: See previousUnique Plant Locations (21 locations)Estimate 21 x $100k = $2,100,000
T-5a. Sequence of Events Recording: $334K T-5b. Fault Recording: $333KT-5c. Dynamic Disturbance Recording: $333K

T-5a. Sequence of Events Recording: $190,000T-5b. Fault Recording: $117,000T-5c. Dynamic Disturbance Recording: $485,000. Note, the net cost would be $485,000 - $190,000 = $295,000, because 2 units are required for both the SER and DDR areas. Total = $602,000
T-5a. Unknown T-5b. Approximately $500,000 T-5c. Unknown
T-5a.Sequence of Events Recording: $0. This assumes that the draft standard will be modified as discussed in T-1.T-5b.Fault Recording: $0.This assumes that the draft standard will be modified as discussed in T-2.T-5c.Dynamic Disturbance Recording: $3 million+.
T-5a: For a stand alone AMS, the cost to purchase and install is approximately is $400k per substation. For a NNGS SOE, cost is approximately 70K per substation.T-5b: For a stand alone DFR, cost to purchase and install is approximately $275K per substation. For a NNGS DFR, cost is approximately $30K per substationT-5c: For an AMS and DFR concurrent installation, cost is about $525K per substation.
T-5a: Infrastructure is already in place. Terminal equipment at new installations is estimated to cost $15k. T-5b: Infrastructure is already in place. Terminal equipment at new installations is estimated to cost $15k. T-5c: Infrastructure is already in place. Terminal equipment at new installations is estimated to cost $15k.
The propsed standard will require X to upgrade existing equipment, with an estimated capital cost of $500,000 per transmission installation and $115,000 per Generating Unit installation. Because it is not yet known how much of the disturbance monitoring equipment already installed already meet the requirements of PRC-002-2, or the scope of new equipment required, the total cost impact cannot be determined at this time.
Unknownn/Estimated at $630,000 (combined for all locations)

CI-1. Please answer the following regarding the estimated costs and benefits of each of the proposed requirements: CI-1a. What is the ongoing long term cost impact (after implementation) of complying with the requirements in terms of equivalent full time employees (EFTE)?

(1) Based on our experience with another project, about 11.4 EFTE will be required in the 4 year phased-in implementation.(2) The Book of Flowgates frequently changes, so we expect some portion of this capital project to be ongoing, and a certain amount of wasted capital.(3) Ongoing maintenance, incremental internal analysis, IT support, and compliance monitoring will cause about 3 EFTE steady state, although Draft 2 is unclear.
0$
0.1 full time person would be required to maintain equipment and comply with this standard moving forward.

0.2 FTE
0.5 EFTE - marginal labor costs associated with verifying data storage, complying with standard, assessing requirements for new facilities
2 EFTEs
2 EFTE's
3 full-time employees.
5 FTE
At least $600,000 over the next decade. This estimate figures in the costs of 5 year assessments, maintenance, compliance and equipment failure.
X would expect to add about one equivalent full-time employee (EFTE) across multiple functions, which may include Engineering, Maintenance, and Planning, in the existing organization.
Based on our present practices we do not project any additional cost impact other than complying with future data requests.
Comments: Two EFTEs in order to support the additional equipment maintenance, disturbance analysis retrieval and monitoring activities, and NERC standard documentation requirements.
Field personnel will be impacted by the requirement to either restore monitoring or have a corrective action plan in place within 90 days. Where we currently have the flexibility to prioritize this work as necessary, this proposed standard will present incremental costs associated with meeting the required timeframe. This will result in increased O&M expenditures that cannot be estimated at this time. There will also be additional, ongoing maintenance and communications costs associated with the additional units installed to meet the obligations of the standard.
For our Transmission department, it will depend on whether the new standard will require the addition of new recording equipment. For our Generation department we would need 3-5 full time employees to check the data and keep record of disturbances and likely contract out to have the DFRs checked every couple years.
Low
Minimal to none
X presently is utilizing a full time equivalent staff of 4 to analyze system disturbances (other job duties also apply for this staff). When a system disturbance occurs the staff responds as a team to analyze and direct further X response actions accordingly. Additionally, there is the cost to test and maintain the equipment which is currently required per PRC-018. There is a rough estimate cost of $1.2M per year in salary and test

and maintenance costs associated with DME application and test/maintenance. This cost has increased in recent years as more DME have been installed and are operational.

Since we are trying to utilize relays to perform as many DME functions as they can and relays are already maintained because they also perform protection functions we're hoping that this standard will have minimal impact. However, there are some real unknowns especially with regards to Dynamic Disturbance Monitoring equipment. Thus, for additional maintenance, troubleshooting required to keep things working, and additional personnel to keep up all the paperwork required for a NERC standard, a rough estimate of additional EFTEs is 3 for a company as large as ours (24000 MW peak load).

The costs of installing new equipment for disturbance monitoring could be significant for our members. We find this standard is unnecessary and NERC should work with the Department of Energy (DOE) to further expand the use of grant money to supply registered entities with funding for these types of monitoring equipment. The prior grants from the DOE have been very successful and we see no reason to require these monitoring devices to be subject to enforceable reliability standards. There is no convincing evidence that these standards are being developed to address a reliability need. We see no justification for industry to allocate resources to disturbance monitoring equipment when there are other priorities that should be addressed first, such as cyber security. This standard will require additional personnel to maintain compliance. Considering that this standard is proposing 14 requirements with numerous sub-requirements, the amount of FTEs will vary with each member cooperative. We feel that having to hire one additional employee to support compliance with this proposed standard is unnecessary.

The long term cost impact (not counting the initial installations) would be the labor required to keep these units online and quickly fix any issues. There would also be labor in analyzing the additional data and handling the compliance documentation. It would involve hiring at least two additional employee to devote a crew to fault recorder work. = 2 equivalent full time employees.

The long term cost impact after implementation is expected to be two (2) EFTE to monitor, inspect and maintain the equipment to meet the requirements.

The long-term cost impact for GOs is expected to be less than one ETFE once the DME has been installed, but installation costs are significant as stated above.

The ongoing long term cost impact in terms of EFTE would be between ½ and 1 EFTE for X.

This proposed standard would have a significant cost impact on the Responsible Entity (Planning Coordinator or Reliability Coordinator) in order to a) establish a process to update DDR locations & monitored elements as the power system changes, and b) periodically monitor availability of the large amount of additional equipment and data.For the Responsible Entity a minimum of 2 additional EFTE would be required to perform the additional ongoing maintenance on 50 additional DDR and 2 additionalDFR.

Three (3) EFTEs

Unknown.

We currently monitor our DMEs from a central location. The current fleet of recorders is a fairly new design and long term reliability presently looks pretty good..002 EFTE Per Unit
Would not expect to increase staffing as a result of the standard. X has significant penetration of these devices in service and in active use to analyze operations.

CI-1. Please answer the following regarding the estimated costs and benefits of each of the proposed requirements: CI-1b. What are the resource benefits (labor, materials, administrative) of implementing these requirements (e.g. being able to effectively and expeditiously analyze disturbances)?

(1) Faults are a regular occurrence. We believe that we have sufficient data already as explained above. More data could shorten time to determine root cause occasionally. At most, a 0.2 EFTE benefit.(2) We've only had one event in 34 years here that DDR would have helped in the analysis. We were still able to determine root cause. No benefit.
1. Being able to analyze faults and disturbances that cannot be analyzed today with older equipment 2. reconstruction of events 3. Faster restoration times associated with microprocessor relay installation
Although installation of DFRs benefit X operations by facilitating more effective and expeditious stability validation after a fault on the system has occurred, the additional resources required to operate and maintain the equipment necessary to comply with the requirements leads X to conclude that there would not be a net benefit in terms of labor, material, administration and other relevant resources.
Based on our present practices we do not project any additional cost impact other than complying with future data requests.
X does not own generation resources. The Company believes that the FR data currently being captured is effective for analyzing disturbances.
Comments: For DDRs, no additional benefits. For Fault Recorders, the entity defined location criteria could facilitate retrieval of additional primary data, or fill in data gaps, and therefore support disturbance analysis personnel efficiency.
Don't see many benefits for GO by installing DDR monitoring. Don't expect many events requiring DDR data.
Due to our mix of protection system relays (microprocessor, solid-state, and electromechanical) we believe these devices simplify and increase our ability to analyze the system behavior.
Fault locating capability provided by the installed DME can help in restoration time for transmission line outages. DME records can aid in determining root cause for misoperations and development of corrective action plans to prevent future misoperations and improve BES reliability.

Having an industry wide standard for disturbance reporting could benefit the personnel who need the data for local and interconnection wide events analysis.
Minimal to none
Minor benefits might include quicker restoration times and a reductions in the number of unknown operations.
Negligible, X already has these systems in place and has been realizing these benefits for several years.
No benefits of implementing the requirements since we already expedite effective analysis for all disturbances. Since we have not been requested to submit analysis data to our regional entity there is no reference to measure and determine if a benefit exists.
Not applicable to X
PRC-002-2 will cause TOs to experience some labor, materials and administrative benefits, due to being able to analyze disturbances more expeditiously with the increased data brought about by installation of new DME. GOs will not experience any labor, materials or administrative benefits from GO-installed DMEs, since GOs do not analyze disturbances.
X already has a fairly extensive spread of fault recording equipment. Additional labor would be needed under this standard to treat the additional required units as more critical components and to ensure the required documentation is kept.
The benefits of the implementation include the ability to access more data to analyze disturbances. As a result, there will be the ability to detect faults more quickly and expedite equipment return to service.
The resource benefit should include manhour savings after a disturbance occurs.
There are no additional benefits to be gained since we firmly believe that we already have adequate disturbance monitoring coverage for our area. This has been proven during the last three years which have included 2 large snowstorm/blizzard events and 3 tropical storm event. This is especially true with regards to DDR data which is rarely requested by our Reliability Coordinator. They are on record as stating that the existing 10 DDR locations provide sufficient coverage.
There would be negligible resource benefits to X, because most of the requirements are already being fulfilled by existing equipment and practices. However, implementation of these requirements would provide a significant benefit to the industry in the collection of more disturbance data and the reporting of that data.
This standard is unnecessary because there are already significant amounts of PMU data to construct sequence of events and other post-event analysis of disturbances. As referenced in the Southwest Blackout Report of 2011, there is a multitude of disturbance monitoring devices installed on the electric grid. The Southwest Blackout Report states, “PMUs are widely distributed throughout WECC as the result of a WECC-

wide initiative known as the Western Interconnection Synchrophasor Program (WISP)." We do not see the cost benefit of requiring additional resources for an issue that is not a high priority for reliability.

Time spent reviewing relay operations in determining root cause is reduced by monitoring. A large manpower savings can be realized when pursuing root cause of generator trips. Likely cause can be rapidly determined and necessary repairs started reducing unavailability.

We already have a large installed based of microprocessor relays for analyzing disturbances. We analyze all transmission disturbances (primarily faults) right as they occur (immediately regardless of day or time of day and regardless of whether the equipment automatically restores). Fortunately, we've never been in a blackout. We have already spent hundreds of millions of dollars installing fiber and upgrading our EHV lines. We are planning many similar upgrades with similar dollar spends to much of our 138kV lines over the next 5 years. Thus, we do not believe that implementing these requirements will help us to analyze disturbances at all. If we were involved in a major disturbance it is possible that some amount of increased Dynamic Disturbance Monitoring data would be helpful, however we have also never fortunately been in such a disturbance. However, we're installing this equipment more over time on our own without oversight. We believe that for SOE and FR that this standard will just create more paperwork and in 10-20 years when all relays are microprocessor, it won't be needed at all (if it is indeed even needed at the present time). We believe the standard is too prescriptive with regards to the amount of DDR data required and many aspects of SOE and fault recording data. There are forces in the industry that are causing DDR data to be added at a quick pace in areas of the country that need it the most (those running closest to the edge) and at a slower pace in areas of the country that are not running so close to the edge. We believe that NERC has gotten to the bottom of all the large scale disturbances of the past 10 to 15 years and written excellent reports on these disturbances. We don't believe that a lot more monitoring would have improved the analyses or indeed that a lot more monitoring is even needed to perform these excellent analyses. Regardless of that, a lot more monitoring is being installed without a NERC DME standard. It's happening on its own as old technology equipment is being upgraded.

We believe that there are no significant benefits from the standard since we have sufficient monitoring equipment to effectively and expeditiously analyze disturbances. The standard will add a huge administrative layer to document compliance.

We believe the incremental benefits over the existing equipment/tools available due to regional requirements are negligible.

Zero - GOs do not analyze Disturbances. For this reason, GOs should not be required to install DME. Where information is needed from generation plants, it should be collected by the TO on their side of the fence or collected using circuits from the GO.

CI-2. Are there alternative method(s) or existing reliability standard requirement(s) not identified in the draft standard which may achieve the reliability objective of the standard that may result in less cost impact (implementation,

maintenance, and ongoing compliance resource requirements)? If so what? Please provide as much additional supporting evidence as possible.

X is not aware of any
No comments.
None other than those already identified.
The process of using short circuit MVA as a selection methodology is just as arbitrary as basing the selection on the number of lines terminating at a station. Both methods yield very similar results. The proposed standard seems to be a reasonable approach to satisfying the objective. No alternatives in terms of a more economical solution are offered.
Throughout the region effective regional criteria exists already and entities have sufficient data recording in place to analyze BES events. Additionally PRC 004 requires each TO to investigate for cause and provide corrective actions. So TO is already required to have this data.
A. Use existing DFR data as required by PRC-018 for event analysis. B. Continue to analyze misoperation reporting data required by PRC-004 to idendtify trends and promote lessons learned.
An alternative method to comply with FR and SOE requirements would be to show that a percentage of your line terminals are all covered by microprocessor relays connected to GPS clocks. The standard should specify an easy way for a Region to audit. An easy way would be to state in the standard that this shall be verified by the Region by checking a small percentage of locations or at least 10. This would alleviate having to make a bunch of big lists and make sure they are up to date. Which lines have microprocessors would be easy to show from existing databases. An alternative method for DDRs would be to set a minimum level for how many stored synchrophasors (or circuit elements in a DDR) must be required for a utility based on its peak load. The number in the standard is current 1 for every 3000 MW of peak load. This number could be changed to something lower, say 1 for every 1500 MW of peak load. Then, let the owner decide where to put them. NERC has had great success investigating events in the past and the data is only getting better on its own. There doesn't need to be a regulatory push to install a bunch of equipment. Having to spend resources

to install a bunch of DDRs will take away from resources upgrading transmission line relaying which provides a much more tangible reliability benefit.

As stated above, there are financial incentive programs through other federal agencies that provide funding for disturbance monitoring equipment. We recommend that NERC work with those programs to develop a technical guideline to ensure these devices are installed and monitoring critical areas of the electric system.

Comments: The Eastern interconnection DDR location flowgate criteria of Section 6.1.4 of the Standard will require an unnecessary excessive number of installations and cost. This criterion should be capped and include consideration of those installation locations being required as a result of the other proposed remaining DDR location criteria.

Do nothing more. (1) Our experience is that existing DME is sufficient “To have adequate data available to facilitate event analysis of Bulk Electric System (BES) disturbances.” Allow some time, say another 5 years, to utilize the existing required DME and the voluntary DME to analyze disturbances. (2) Document instances of insufficient data, and the incremental resource cost actually required to analyze disturbances. If that incremental cost is significant, revisit the standard.(3) Perhaps there are entities or regions that have a greater demonstrated need. We encourage voluntary DME additions or regional standards for them.

It is already in the entities’ best interests to monitor their systems for disturbance data, so the new standard is unnecessary.

Make PRC-002-2 applicable only for the parties that have expertise with DME and use the information gathered by these devices, i.e. TOs, unless the GO owns breakers or other relevant equipment in the TO’s system causing the TO not to have access to the needed signals.

NPCC has an existing NERC regional standard that addresses DME. PRC-002-NPCC-01. This standard uses a different methodology to determine DME locations and imposes more stringent DME technical requirements than the PRC-002-2 draft standard.

Other devices can record this information such as relaying, existing dfrs, neighbors equipment. The overall experience in the SERC region is that the existing regional criteria have provided sufficient data recording capability for previous BES events.

Possibly make PRC-002-2 applicable only for the parties that have expertise with DME and use the information gathered by these devices, i.e. TOs. Perhaps the GO limit of responsibility can be “provision of specific signals V, I, P, Q from the generators to the TOs or DPs who own the DME equipment”.

Regional requirements regarding disturbance monitoring equipment exist in Guides. The location requirements are system topography-based. It is unknown if the proposed PRC-002-2 method based on maximum fault current analysis would match up to existing locations. However, the existing requirements provide sufficient data for disturbance monitoring for our company.

We feel the requirements for installation of DDR equipment is excessive and provides minimal benefit. Although we concur with the benefit associated with the needed DDR equipment on Transmission Facilities, we feel the Generation locations are excessive when implemented at the 300MW threshold. Additionally the requirement to install DDRs at all flow gate lines is excessive and should be limited to those that contribute some level to the flow gate.

CI-3. How long would it take your organization to implement full compliance to the standard as written? What would affect the implementation (i.e. outage scheduling, availability of materials, human resources, etc.)?

(1) It has taken three years of significant effort to expand X's phasor measurement unit complement to its present number 38 installed devices, which includes 6 devices at three NERC locations which were in place prior to commencing another Project). (2) If we were to install additional phasor measurement units to fulfill the requirements for dynamic disturbance monitoring equipment as described in this standard, it would require expansion of the number of such devices by approximately 180 or so. (3) We believe that this could take another 10 years or so to install these devices, and have them configured and calibrated properly, as well as shore up data storage requirements and network communications bandwidth at the data concentrator sites to handle the huge increase in network traffic.

1). 3 years 2). Budget restrictions would affect

12 to 18 months to engineer, purchase materials and accept delivery, and schedule outages and manpower for installation for the one station that would be affected.

1-2 years after potential new locations are identified

5 years, based on budgeting, outage schedules & resource limitations

Approximately 3-6 months

Comments: It would be reasonable that a DME installation project program of the resulting size being proposed be implemented over a ten year period due to manpower resource limitations (including contractors), annual funding considerations, and outage scheduling considerations.

Due to PRC-002-RFC-01, X has more DME installed than the required 10 locations determined per the NERC Median Method spreadsheet (process to determine bus locations for PRC-002-2). There will be no cost to implement PRC-002-2 going forward.

Due to the large quantity of additional DDR required to address IROL situations in our operating region, it is estimated that an additional 5 years would be required to identify and install the equipment necessary to comply with this standard. The Responsible Entity would require several months to implement requirements R6 and R7 of this proposed standard (R6 requires the Responsible Entity to specify DDR locations and monitored elements; R7 requires the Responsible Entity to notify TOs and GOs of DDR locations and monitored elements).

X believes the proposed Implementation Plan is sufficient for our needs.
Four to eight years, mostly waiting for generation plant planned outages.
Implementation time is unknown; however, it would factor in the examples given in the question as well as project scheduling, design time, and the actual locations for DME.
It could potentially take X several years to implement full compliance with the draft PRC-002-2 standard as written based on the number of BES bus locations identified in R1 and the number of required outages needed.
It is unknown for our Transmission department because we have not performed the analysis to see where new equipment will be required pursuant to the new standard. For our Generation department it would be around 3-5 years depending on outage schedules and when the standard becomes effective.
It would take 5-6 years. Managing a tradeoff between funding direct reliability improvement projects and items such as DFRs would affect the implementation. We have been doing a pretty good job of balancing the two.
It would take approximately 5 years to implement. This is affected by budgeting, schedules, outage schedules, material availability.
It would take six (6) years to implement full compliance. The implementation would be affected by outage scheduling in addition to time for engineering activities and availability of materials.
X estimates it would take five years to implement full compliance to the standard as written. The effort would require outage scheduling, human resources, and availability of materials due to the industry wide effort. The SDT should consider the impact of the implementation timeline upon the DFR industry's capacity to make the estimated number of units available to meet demand.
Not applicable to X
Our member cooperatives have limited resources and would require significant time to budget for additional staff and equipment. With the approval of CIP version 5 standards, there is a significant amount of resources being allocated for cyber security. We believe there is more cost benefit for cyber security than disturbance monitoring equipment, especially when this type of project could be handled through a financial incentive program like the --- as stated above. Requiring installation DMEs will only distract registered entities from important activities such as complying with cyber security standards and could, in fact, be detrimental to reliability.
Reasonable expectations would be 48-60 months to fully comply with PRC-002-2. Outage scheduling, human resources, etc. could affect the implementation of this standard.
Recommend a minimum implementation timeframe of 24 months following identification of facilities required

by RE. As with any new standard, internal processes need to be developed to support compliance with the standard (e.g. identification of SMEs, procedures for storing/retrieving data, identification of any gaps, project planning, outage scheduling/construction, etc).
Several years (waiting for generation plant planned outages)
Several years due to outage scheduling and human resources as well as quantity of monitoring needing to be installed.
This implementation is estimated to take 6 to 8 years. The current draft implementation period of 100% compliance within 4 years is not long enough to ensure that all of the requirements can be implemented without putting undue burden on utilities.
Three to five years, based on work scheduling, ordering of materials, manpower availability, and the budgeting/approval process.
Three years due to our internal budgeting process.
Unknown until equipment specifications are developed and the production capacity of the equipment vendors is known.
We don't think the standard is necessary. However, as is, 10 years would be a reasonable amount of time to install all this equipment.

CI-4. What NERC Functional Model registered entity or group do you will believe will benefit from this standard? (i.e. Balancing Authorities, Load-customers, etc.) and is there a value –either cost or socio-economic impact associated with that benefit? Does a NERC Functional Model registered entity or group other than the one you identified bear initial or ongoing costs related to this standard (bear a cost without receiving a benefit)?

T Operator, T Planner, T Owner, GO Due to financial impacts to company, any additional cost required does not add value.
A number of entities will benefit from the DME installations. The proposed DME installations provide useful data for post event forensic analysis. Customers o f the BES - generators and load customers - will see a reliability benefit as the Transmission Owner /Transmission Operator will have greater access to information to better review/analyze events on the BES. Additionally, the Transmission Planner/Planning Coordinator will find the data helpful in performing model validations that will be required in the proposed new MOD-033 standard.
All should benefit if the reliability of the BES is increased.
Any utility with an asset fleet subject to disturbances will benefit from the gathering and analysis of

disturbance data which can reduce the time required for troubleshooting, fault locating, etc. In general we feel the costs borne by this requirement are properly allocated, i.e. asset owners who install disturbance monitoring equipment will have better data to make more informed decisions about their assets.

As a Transmission Owner and Operator, we find value in using these devices to quickly identify patterns that could lead to failures, or if a failure occurs, these devices help to identify the problem quickly, so that crews can be deployed quickly to resolve the issues found, which is why we've already installed 12 unites at various BES site, and plan to install more units at other Non-BES sites.

As stated before, it is felt by GOs that only TOs and TOPs will benefit from this standard. GOs would bear initial and ongoing costs related to this standard without receiving any benefit. Possible alternative = NERC Events Analysis (let them install and maintain equipment)

X believes the FR data currently being captured is effective for analyzing disturbances and performance of the transmission protection systems that the Company owns. X is not certain that the anticipated cost of increasingly prescriptive data requirements, which will eventually result in the installation and maintenance of new equipment, is balanced by any perceived benefit to entities. The Company strongly believes that any entity that benefits from this standard should bear the costs.

Comments: All of the subject standard applicable Functional Entities will receive benefit by capturing the appropriate data to facilitate the analysis of BES Disturbances.

Everyone will benefit from reliability gains occasioned by the information gathered by DME. This goal would best be served by having DME be specified, installed, downloaded and maintained by the parties with the requisite expertise (Transmission).

Everyone will benefit from reliability gains occasioned by the information gathered by DME. This goal would best be served by having DME be specified, installed, downloaded and maintained by the parties with the requisite expertise (Transmission).

Expect PC and TO receive most benefit but GO bears cost with little benefit.

Given that PMUs have become ubiquitous as evidenced by the 2011 Southwest Blackout Report, we do not believe any function would significantly benefit from the incremental installation of DMEs required by this proposed standard.

Groups that will benefit from this standard are as follow: BA, RC, GO, GOp, TO, TOp, and possibly the LSE. Groups that will bear either initial or ongoing costas are as follow: TP, TO, TOp, GO, and the GOp.

Load-Customers; there would only be a socio-economic benefit if the ability to analyze effectively and expeditiously resulted in avoided future outages or restore service that minimized customer impacts to sales or production. Within the structure of NERC’s functional model, X believes Compliance Enforcement Authorities, Transmission Planners, Transmission Owners, Transmission Operators, and Planning Authorities would primarily benefit from the installation of sequence of events and fault recording equipment.

None. How much has disturbance analysis cost NERC itself in the last decade?
Planning Coordinators would benefit from this standard in conjunction with the MOD-B project for dynamic and static model validation. This would also enable protection engineers to have sufficient data in order to perform their analysis, in support of Generator Operator, Transmission Operator, and Reliability Coordinator needs.
Planning Coordinators/Reliability Coordinators. The value will come from the reconstruction of events to identify how problems occurred which will allow organization to move to correct the problems. It is difficult to assess costs and benefits to other entities.
Reliability Coordinators and Planning Coordinators may benefit from this standard in that event reports would be compiled and provided to them by Transmission Owners and Transmission Operators. Transmission Owners and Generator Owners would incur the initial costs associated with installing disturbance monitoring equipment.
See CI-5. We do not believe the standard is necessary, costs and benefits will borne by the appropriate entities over time through a normal process as old technology is updated.
The Applicable Entities will bear a large cost without receiving a benefit
The groups that benefit likely do not belong to a single NERC Functional Model but rather to regions where existing requirements are not in place. Those groups would be the best candidates for answering this question.
The Planning Coordinator and Transmission Owner may benefit from this standard by having the disturbance data that can be used for modeling. The Generation Owner may benefit by having the data for use in troubleshooting. The Transmission and Generator Owner will bear the cost regardless of realizing a benefit.
The TO, GO, DP will benefit along with the load customers because adequate DME coverage allows the performance of BES protection systems to be evaluated and improved upon as necessary.
This standard places some responsibilities on the TO/GOs, and some on the Balancing Authorities (BA) with seemingly no order. The BA might be the best organization to determine the requirements of this standard. TO/GOs in NY already follow a "DDR Location Study," issued by the NYISO on 8/26/13. It would be more efficient to answer to one set of guidelines, that a BA can issue on following this standard.
TOs will have direct benefit and others functions will have indirect benefit by having certainty in the causes of disturbances for use in developing targeted reliability program actions.
We believe the RC and RRO would gain the most benefit from the information collected through compliance with this standard. However, the initial cost and ongoing costs are spent by the entity in order to install the devices on their systems to maintain compliance with the standard.

CI-5. Do you have any other comments? If so, please provide suggested changes and rationale. Describe the size of your organization in broad general terms, e.g. GO-Total installed MWs, TOs circuit miles by kV and total load served, etc.

As noted earlier: Although we concur with the benefit associated with the needed DDR equipment on Transmission Facilities, we feel the Generation locations are excessive when implemented at the 300MW threshold. Additioanally the requirement to install DDRs at all flow gate lines is excessive and should be limited to those that contribute some level to the flow gate.

X recommends discontinuing development of PRC-002 and continuing to utilize existing DFR data per PRC-018-1. The Company will continue to provide comments to the SDT.

Comments: 1) The draft standard DDR installation location criteria using “all” flowgates will result in an excessive number of DDRs and associated costs, and is not justified by the benefits. Suggest capping the number of DDR installations and include consideration of those installations already being required as a result of the other DDR location criteria.2) We believe our existing DDR Regional installation location criteria using Regional Planning Committee resources familiar with the geography and electrical systems in question have provided adequate coverage and are a better location criteria methodology. 3) The Planning Coordinator and/or the Reliability Coordinator have unlimited authority to order the Transmission Owner to add disturbance recording devices, which in this standard appear suspiciously as if a vendor has had extensive input, maybe even undue influence. 4) These devices are not redundant with a hot failover capability, yet, the requirements are absolute. They make no allowance for downtime due to maintenance or for scheduling a response to failures as opposed to immediately responding to all failures. Requirements written without clear acknowledgement that these are real-world computing devices which can hiccup and can fail will be a compliance challenge.5) We have an extensive installed base of devices that may be rendered obsolete by this standard (Are SEL-521’s capable of the technical requirements within this standard? Are the PMUs capable?). Point being, this looks very expensive no matter how little obsolescence is created.6) This standard looks a lot more like a procedure than a standard. It seems to get into the “how” much more than the “what”.

It is respectfully requested that the drafting team consider current equipment specifications in order to ensure that the new standard does not exceed these specifications.

X anticipates using one device to provide all three required functions.

X believes that this standard has value and provides a viable alternative to our regional standard PRC-002-NPCC-1 with the exception of the DDR location requirements. The location of DDR to provide adequate disturbance visibility should be determined by the Reliability Coordinator/Planning Coordinator who is most cognizant of the Bulk Power System topology for their area.

R4 is not clear regarding whether the TO or GO is responsible for the monitoring and it should indicate that it is the owner of the Elements.

Since the number and size of some devices will be dependent on where the RRO requires they be placed, having an estimate from the RRO of which paths they will require them on would be necessary before more accurate estimates can be made on total costs.

Thank you for the opportunity to comment.

The costs associated with equipment installation above are not additive, i.e., each DTR would have both SER and Fault data recording (and possibly dynamic disturbance monitoring) in the same equipment. The costs are for a single set of recording equipment and the costs would be in integral multiples if more than one unit is required at a site. This is especially likely at sites with multi-breaker bus configurations because it appears that three phase voltages would have to be monitored and recorded on each individual line.

The Requirement R 14 should be removed as it provides no value. This goes beyond what is required and describes how a TO should be doing work?

The X are not directly responsible to comply with the PRC-002 requirements but they have reviewed the questions in the CEAP Phase Two survey as well as the Phase Two Cost Effective Analysis Process. The SRC (MISO abstaining) submits several questions regarding the survey for this Project and how the results will be utilized. The SRC identified several areas of concern: o The timing to conduct this Pilot on the PRC-002 standard does not seem appropriate given the standard has failed ballot at a low 43%. For examples, questions/issues arise with respect to: On what basis should entities assess their costs - on requirements as proposed and failed, or on what each entity believes should be applicable or in current practice? If and when the standard is revised substantively, will another survey be conducted and if so, does it render the current survey irrelevant? If not, what value do the results of the current survey provide in arriving at the final draft standard? o The CEAP conflicts with the practice of concurrent balloting. The fluidity of requirements can possibly return false or inaccurate information that is not consistent or reflective of whatever final approved requirements are established. o The response rate has a great potential to skew results. E.g. - If only one segment or size/type of entities responds. Therefore this raises our concern on what checks and balances are in place to assess cost effectiveness? o The CEAP stipulates that the SC SPCS will “extrapolate” the data. - We suspect that members of the SPCS are not statisticians and hence they may not have the expertise to make such determinations. We urge NERC to consider utilizing proper expertise to develop the cost data since ultimately, the cost effectiveness assessment should be provided to the industry and decision makers so they can draw their own conclusions. o The process seems to lack transparency. It is not apparent to us whether or not the data collected will be posted and responded to. We believe the raw data and the summary results of the CEAP should be posted along with ballots throughout the standard development process and added to the final Board approval package and FERC filing.

There is a concern that the requirements, as written, could cause an overlap in the amount of DDR and other fault recording data equipment required by the TO and GO. This could lead to redundant fault recording equipment at a single bus and an unnecessary cost would be incurred by the Registered Entity without improving the reliability of the BES.

We believe that the natural progression from older technology to modern technology for protection and control equipment is happening on its own. Older relays are being replaced due to obsolescence, because they are problematic, and because of all the benefits of modern relays including better disturbance analysis. We believe that a standard is not needed to force the issue. If a standard must be written, it should be extremely low burden and there should be a recognition that in 10 years or so that it is likely a standard will no longer be needed as the natural progression from older to newer technology will likely be nearly complete

industry-wide.
We maintain that the responsibility for dynamic disturbance recording should be assigned to Transmission Owners, since they are able to provide this capability most efficiently.