May 31, 2011

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***North American Electric Reliability Corporation***
Docket No. RM11-___-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d) (1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC") regulations seeking approval of proposed Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring, and two associated new definitions included below and set forth in **Exhibit A** to this petition:

> **Current Zero Time —** The time of the final current zero on the last phase to interrupt.
>
> **Generating Plant** — One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

These proposed terms will be added to the NERC Glossary of Terms as applicable only to entities in the Northeast Power Coordinating Council ("NPCC") footprint.

The proposed Regional Reliability Standard and defined terms were approved by the NERC Board of Trustees during its November 4, 2010 meeting. NERC requests the standard and defined terms become effective upon the first day of the first calendar quarter following the effective date of a Final Rule in this docket.

This petition consists of the following:

- this transmittal letter;
- a table of contents for the entire petition;
- a narrative description explaining how the proposed Regional Reliability Standard meets FERC's requirements;
- Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring and Implementation Plan, submitted for approval (**Exhibit A**);
- the NERC Board of Trustees' Resolution approving PRC-002-NPCC-01 — Disturbance Monitoring and directing it be filed with FERC (**Exhibit B**);
- the complete Development Record of the proposed Regional Reliability Standard (**Exhibit C**);
- the Standard Drafting Team roster (**Exhibit D**); and
- the Violation Severity Level and Violation Risk Factor Guideline Analysis (**Exhibit E**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Andrew M. Dressel
Andrew M. Dressel
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket Nos. RM11-__-000** **)**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED NPCC REGIONAL RELIABILITY STANDARD PRC-002-NPCC-01 — DISTURBANCE MONITORING

Gerald W. Cauley
President and Chief Executive Officer
David N. Cook
Senior Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Holly A. Hawkins
Assistant General Counsel for Standards and Critical Infrastructure Protection
Andrew M. Dressel
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955– facsimile
holly.hawkins@nerc.net
andrew.dressel@nerc.net

May 31, 2011

TABLE OF CONTENTS

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby requests the Federal Energy Regulatory Commission ("FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5, proposed Regional Reliability Standard, PRC-002-NPCC-01 and two associated new definitions, included in **Exhibit A**. The proposed Regional Reliability Standard includes two defined terms as follows:

Current Zero Time — The time of the final current zero on the last phase to interrupt.

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

These terms do not presently appear in the NERC Glossary of Terms, and they do not conflict with existing glossary terms.

This petition is the first request by NERC for FERC approval of this proposed Regional Reliability Standard. The Regional Reliability Standard proposed will be in effect only for applicable registered entities within Northeast Power Coordinating Council Region ("NPCC"). NERC continent-wide Reliability Standards do not presently address the issues covered in this proposed Regional Reliability Standard.

On November 4, 2010 the NERC Board of Trustees approved PRC-002-NPCC-01 — Disturbance Monitoring. NERC requests that FERC approve this Regional Reliability Standard and make it effective upon FERC approval for the section of the NPCC region that lies within the United States. **Exhibit A** to this filing sets forth the proposed

[1] NERC has been certified by FERC as the Electric Reliability Organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order).
[2] 16 U.S.C. 824o.

Regional Reliability Standard and Implementation Plan. **Exhibit B** is the NERC Board of Trustees' resolution to approve the proposed Regional Reliability Standard. **Exhibit C** contains the complete record of development for the proposed Regional Reliability Standard. **Exhibit D** includes the standard drafting team roster. **Exhibit E** is the Violation Severity Level ("VSL") and Violation Risk Factor ("VRF") guideline analysis.

NERC is also filing the proposed PRC-002-NPCC-01 Regional Reliability Standard and associated documents with the applicable governmental authorities in Canada.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

Gerald W. Cauley
President and Chief Executive Officer
David N. Cook*
Senior Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

*Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

Holly A. Hawkins*
Assistant General Counsel for Standards and Critical Infrastructure Protection
Andrew M. Dressel*
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
holly.hawkins@nerc.net
andrew.dressel@nerc.net

III. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[3] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. Section 215 of the FPA states that all users, owners and operators of the Bulk Power System in the United States will be subject to FERC-approved Reliability Standards.

b. Basis for Approval of Proposed Regional Reliability Standard

Section 39.5(a) of FERC's regulations requires the ERO to file with FERC for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to be made effective. FERC has the regulatory responsibility to approve standards that protect the reliability of the Bulk Power System. In discharging its responsibility to review, approve, and enforce mandatory Reliability Standards, FERC is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress:

> FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4]

When evaluating proposed Reliability Standards, FERC is expected to give "due weight" to the technical expertise of the ERO and to the technical expertise of a Regional Entity *organized on an Interconnection-wide basis* with respect to a Reliability Standard

---

[3] 16 U.S.C. § 824o.
[4] 16 U.S.C. § 824o(d)(2).

to be applicable within that Interconnection. Order No. 672 provides guidance on the factors FERC will consider when determining whether proposed Reliability Standards meet the statutory criteria.[5]

A Regional Reliability Standard proposed by a Regional Entity must meet the same standards that NERC's Reliability Standards must meet, *i.e.*, the Regional Reliability Standard must be shown to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[6] FERC's Order No. 672 also requires additional criteria that a Regional Reliability Standard must satisfy: A regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard (which includes a regional standard that addresses matters that the continent-wide Reliability Standard does not), or (2) a Regional Reliability Standard that is necessitated by a physical difference in the Bulk Power System.[7]

NPCC is not an "interconnection-wide" Regional Entity, and its standards are intended to apply only to that part of the Eastern Interconnection within the NPCC geographical footprint. As discussed in the *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure*,[8] NPCC's standards are developed according to the following characteristic attributes:

- **Open —** The NPCC Regional Reliability Standards Development Procedure provides any person the ability to participate in the development of a standard. Any entity that is directly and materially affected by the reliability of the NPCC's Bulk Power System has the ability to participate in the development and approval of reliability standards. There are no undue

[5] *See Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs*., ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").
[6] Section 215(d)(2) of the FPA and 18 C.F.R. §39.5(a).
[7] Order No. 672 at P 291.
[8] The *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure* is available at http://www.npcc.org/regStandards/Overview.aspx

financial barriers to participation. Participation in the open comment process is not conditional upon membership in the ERO, NPCC or any organization, and participation is not unreasonably restricted on the basis of technical qualifications or other such requirements. NPCC utilizes a website to accomplish this. Online posting and review of standards and the real time sharing of comments uploaded to the website allow complete transparency.

- **Inclusive —** The NPCC Regional Reliability Standards Development Procedure provides any person with a direct and material interest the right to participate by expressing an opinion and its basis, have that position considered, and appealed through an established appeals process if adversely affected.

- **Balanced —** The NPCC Regional Reliability Standards Development Procedure has a balance of interests and all those entities that are directly and materially affected by the reliability of the NPCC's Bulk Power System are welcome to participate and shall not be dominated by any two interest categories and no single interest category shall be able to defeat a matter. This will be accomplished through the NPCC Bylaws defining eight sectors (categories) for voting.

- **Fair Due Process —** The NPCC Regional Reliability Standards Development Procedure provides for reasonable notice and opportunity for public comment. The procedure includes public notice of the intent to develop a standard, a 45 calendar day public comment period on the proposed standard request, or standard with due consideration of those public comments, and responses to those comments will be posted on the NPCC website. A final draft will be posted for a 30 calendar day pre-balloting period, and then a ballot of NPCC Members will be conducted. Upon approval by the NPCC Members, the NPCC Board then votes to approve submittal of the Regional Standard to NERC.

- **Transparent —** All actions material to the development of Regional Reliability Standards are transparent and information regarding the progress is posted on the NPCC website as well as through extensive email lists.

Proposed NPCC standards are subject to approval by NERC, as the ERO, and FERC before becoming mandatory and enforceable under Section 215 of the FPA.[9] The NPCC Regional Reliability Standard was developed in an open, transparent, and inclusive fashion. During development of the standard, workshops were conducted jointly with other Regional Entities and NPCC members including Regional Transmission Organizations as well as state regulators. The proposed standard is widely supported by

[9] 16 U.S.C. 824o.

the NPCC ballot body and regulatory agencies that see this as a meaningful and necessary step forward in solving a longstanding problem. The standard was reviewed by NPCC legal counsel for consistency with the provisions and stated goals of the Federal Power Act and Chapter 39 of FERC's regulations.[10] As a condition of NPCC membership, all NPCC Members[11] agree to adhere to the NERC Reliability Standards in addition to the NPCC Regional Reliability Standards. NERC Reliability Standards and the NPCC Regional Reliability Standards are both enforced through the NPCC Compliance Program.

As previously noted, NPCC is a Regional Entity, but is not organized on an Interconnection-wide basis. Therefore, NERC is not required to rebuttably presume the proposed standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The proposed Regional Reliability Standard was developed using the *Northeast Power Coordinating Council, Inc. Regional Reliability Standard Development Procedure*[12] that enables all parties with an interest in the standard to participate in its development. NERC's public posting of this proposed Regional Reliability Standard did not elicit any significant technical objection. NERC determined that the proposed standard meets the criteria for consideration and approval as a Regional Reliability Standard.

[10] 18 C.F.R. §39 (2011).

[11] As defined in Section IV.B of the NPCC Corporation By-laws. Available at: http://www.npcc.org/documents/aboutus/BusPlanBylaws.aspx.

[12] The Northeast Power Coordinating Council, Inc. *Regional Reliability Standard Development Procedure*. Available at http://www.npcc.org/regStandards/Overview.aspx.

IV. JUSTIFICATION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD

This section summarizes the development of the proposed Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring; describes the reliability objectives to be achieved by the Regional Reliability Standard; explains the development history of the Regional Reliability Standard; and demonstrates how the standard meets the FERC criteria for approval. NERC, in its analysis and approval of the proposed Regional Reliability Standard, determined that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

The complete development record for the proposed Regional Reliability Standard is provided in **Exhibit C** and includes the development and approval process, comments received during the industry-wide comment period, responses to those comments, ballot information, and NERC's evaluation of the proposed standard.

a. Basis and Purpose of Standard PRC-002-NPCC-01 — Disturbance Monitoring

The proposed regional standard, PRC-002-NPCC-01 — Disturbance Monitoring, is designed to ensure that adequate disturbance data is available to facilitate Bulk Electric System ("BES") event analyses. PRC-002-NPCC-01 addresses the adequacy and security components of reliability by requiring that Disturbance Monitoring Equipment ("DME") be available to monitor the BPS System response to disturbances. The BPS is subject to Faults or Disturbances, and scheduled and unscheduled outages which can range from transient faults on transmission lines to forced System Element outages. The event analysis data obtained through implementation of this standard will be used to better design and operate the BPS to withstand System disturbances which may cross state and international boundaries. Investigation of each incident and application of any lessons learned is critical to optimize the performance of Protection Systems with the goal of preventing future incidents from becoming wide-area disturbances. The tools required to perform post-incident analyses include DME which can capture pre-event, event, and post-event conditions with a high degree of accuracy.

The proposed standard contains 17 requirements that establish Disturbance Monitoring for entities within the NPCC region. The proposed standard is included in **Exhibit A** to this filing.

b. Proposed Terms

NPCC is proposing the addition of two new terms to the NPCC Glossary of Terms: "Current Zero Time" and "Generating Plant". These terms do not presently appear in the NERC Glossary of Terms, and they do not conflict with existing terms. NPCC determined that it was necessary to define "Current Zero Time" because Fault recording capability should be able to determine the precise time of circuit interruption. This precise time could only be clarified by adding a new defined term; thus, adding clarity to the Fault recording requirements.

Likewise, NPCC determined that it was necessary for clarity to define "Generating Plant." The "Generating Plant" definition was created to address the need to clarify the sequence of event recording capability in Requirement R1 and the fault recording capability requirement in Requirement R4. One fault recorder is able to capture all the information from a single contingency affecting all the generators at a "Generating Plant" at a single physical location. Therefore it is more efficient to use just one piece of DME since multiple DMEs at the same physical location would record the same information.

c. Order No. 672 Criteria

In Order No. 672, FERC identified criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standards have met or exceeded the criteria:

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

The proposed Regional Reliability Standard, PRC-002-NPCC-01 — Disturbance Monitoring, is designed to ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. PRC-002-NPCC-01 addresses the adequacy and security components of reliability by requiring the functional entities to provide the equipment to monitor the BES response to System disturbances as well as scheduled and unscheduled System outages. The analysis that this information supports will be used to better design and operate the BES to withstand and mitigate scheduled and unscheduled outages as well as System disturbances. PRC-002-NPCC-01 — Disturbance Monitoring contains 17 requirements that identify the proper locations for installation of Sequence of

Events ("SOE") recorders, Fault recorders, and DDRs; the equipment to be monitored; and the data to be captured by this equipment.

2. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others.

> Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

The proposed Regional Reliability Standard is only applicable to Transmission Owners, Generator Owners, and Reliability Coordinators within the NPCC region. These entities are users, owners, or operators of the BPS.

3. Proposed Reliability Standards must consider any other relevant factors.

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

All comments and concerns were addressed using the *Northeast Power Coordinating Council Standards Development Procedure* which is consensus-based, technically sound, and open to the public and bordering entities that may be impacted by a Regional Reliability Standard. No other factors were identified as necessary for consideration by the standard drafting team in the development of the proposed Regional Reliability Standard.

4. Proposed Reliability Standards must contain a technically sound method to achieve the goal.

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and

> engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

The proposed Regional Reliability Standard contains a technically sound means to achieve this goal.

In order to properly analyze an event on the BPS, it is important to know the relative changes in circuit breaker status, control, and protection signals. SOE recorders capture the equipment and Protection System sequence of events for monitored changes of state occurring in substations, switchyards, or power plants. With this information, Fault clearing times can be determined and Protection System and BPS behaviors during the event be more accurately evaluated. This information is used in conjunction with records from Fault recorders and DDRs to complete post-event analyses. For non-Fault conditions, the SOE record may be the only recorded data available.

PRC-002-NPCC-01 — Disturbance Monitoring Requirement R1 requires that each Transmission Owner and Generator Owner provide SOE recording capability by installing SOE recorders or as part of another device, such as Supervisory Control And Data Acquisition (“SCADA”), a Remote Terminal Unit (“RTU”), a generator plant Digital (or Distributed) Control System (“DCS”) or part of Fault recording equipment. The capability must be provided at all substations and at locations where circuit breaker operation could affect continuity of service to radial Loads greater than 300MW, initiate drops 50MVA or more from the nameplate Rating or greater of a Generation unit, or create a Generation/Load island. SOE recording capability must also be provided at generating units above 50MVA nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA nameplate Capacity, and at Generating Plants above 300MVA nameplate Capacity (part 1.1). At each of the locations specified in part 1.1 the recorders must monitor Transmission and Generator circuit breaker positions (part 1.2.1), Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1 (part 1.2.2), and Teleprotection keying and receipt (part 1.2.3). The purpose of event analysis is not only to find out what causes an event, but also how the System responded and evolved during the event. Knowing the status change of generators during a BES event greatly helps protection engineers to understand how a System event developed and to prepare for future events.

The 300MW radial Load was selected for inclusion as the baseline for Requirement part 1.1 based on the engineering judgment and operating experience of the NPCC members. This is also consistent with NPCC document A-15 *Disturbance Monitoring Equipment Criteria*,[13] and the possibility of the loss of 300MW escalating to a wider area disturbance. Furthermore, the drafting team noted that the tripping of a fully loaded 1200 Amp 138kV circuit breaker would drop 300MW of load.

Ideally, every generator registered in NPCC should be monitored. However, this would require a tremendous commitment of resources. As a compromise, the drafting team decided that it would only be necessary to monitor significant generation sources with Capacities of at least 50 MVA for a single unit and 300 MVA for a Generating Plant. The drafting team set these limits after evaluating the relative contributions of the smaller and the larger generators to System events, and deciding that monitoring these

[13] *Disturbance Monitoring Equipment Criteria* NPCC Document A-15 (2007). Available at: http://www.npcc.org/documents/regStandards/Criteria.aspx.

larger generating units would provide more important and useful information for event analysis. Subject matter experts outside of the drafting team were also consulted to help arrive at these thresholds. The loss of a particular single generator might not cause a System-wide reliability concern, but there was concern that losing a cluster of generators due to a local disturbance could cause widespread impact. These generation thresholds are consistent with the existing NPCC document A-15 Disturbance Monitoring Equipment Criteria.

In reporting circuit outages for Wide Area Disturbances, the most precise time to use for the circuit interruption is Current Zero Time. The Current Zero Time is the time of fault clearing when the current in the last monitored phase goes to zero. Fault recording capability is necessary to determine the Current Zero Time for the loss of BPS Elements.

Fault recorders electronically store System waveforms and can be used to reproduce those System waveforms to analyze transients and abnormalities in System frequency. Requirement R2 of the proposed Regional Reliability Standard requires each Transmission Owner to provide Fault recording capability for: all transmission lines (part 2.1), autotransformers or phase-shifters connected to buses (part 2.2), shunt capacitors, shunt reactors (part 2.3), individual generator line interconnections (part 2.4), Dynamic VAR Devices (part 2.5), and HVDC terminals (part 2.6) at facilities where Fault recording equipment is required to be installed as per R3.

Another critical piece of information in post Fault analysis is the Fault duration, and that time is provided by the Fault recorders. Requirement R3 of the proposed standard requires that each Transmission Owner have Fault recording capability that determines the Current Zero Time for loss of BES transmission Elements.

Requirement R4 of the proposed standard requires that each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up ("GSU") transformer to a BES Element unless Fault recording capability is already provided by the Transmission Owner. Because of the importance of the data captured by Fault recorders, this requirement ensures that all BES facilities will be monitored. Using the 200 MVA threshold for fault capability captures sufficient fault waveforms from all generation sources that are connected to BPS buses. Additionally, it is also consistent with the 200 MVA threshold stipulated in NPCC document A-15 Disturbance Monitoring Equipment Criteria. Moreover, the requirement recognizes that a duplication of equipment monitoring the same quantities is not needed.

Because there are certain electrical quantities that must be known and processed for post event analysis, it is necessary to record these quantities. Requirement R5 of the proposed standard requires that each Transmission Owner and Generator Owner record for Faults sufficient electrical quantities for each monitored Element to determine: three phase-to-neutral voltages (common bus-side voltages may be used for lines) (part 5.1), three phase currents and neutral currents (part 5.2), polarizing currents and voltages, if used (part 5.3), frequency (part 5.4), and Real and Reactive Power (part 5.5).

Voltage is a necessary quantity needed for post event analysis. Ideally, monitoring all three phases eliminates the need for calculating an unmonitored phase voltage quantity. Three phase to neutral voltages are suggested because they serve as a check of the health of the voltage sources and are needed because the voltage sources may be used to supply protective relays. Monitoring three of the four voltage quantities (three phases and neutral) allows for the calculation of the unmonitored quantity. Current, like voltage, is a necessary quantity needed for post event analysis. Monitoring all three phases also eliminates the need for the uncertainty in calculating an unmonitored current. Monitoring all three phase currents are specified because they serve as a check of the health of the current sources (current transformers), because the current sources may be used to supply protective relays. Monitoring three of the four current quantities allows for the calculation of the unmonitored quantity. Monitoring polarizing currents and voltages, if used, provides an additional quantity for post event analysis. Monitoring polarizing currents and voltages monitors the health of the current and voltage sources during Fault conditions. Monitoring frequency is important to analyze generator performance during events, and any resonances and transients that might be caused by a Disturbance. Finally, monitoring Real and Reactive Power provides data that can be used to satisfy the power transfer equation during post event analysis, and a power System's response and contribution to an event.

When recording the monitored data, it is necessary for the equipment to have the capability to capture the intended information with enough detail to make it meaningful. Requirement R6 of the proposed standard requires that each Transmission Owner and Generator Owner provide Fault recording with the specific capabilities in parts in 6.1 through 6.4. Part 6.1 specifies that Fault recorders record duration be a minimum of one (1) second. The one second specification for record duration allows for the capture of a transient, a time stamp, the requirements of local relays for reproducing events in the relays, and the expected local clearing time for Faults. Part 6.2 specifies that Fault recorders must have a minimum recording rate of 16 samples per cycle. This minimum recording rate was selected to accommodate existing recording equipment, and sufficiently captures the data that is required for post event analysis. Part 6.3 specifies that Fault recorders be set to trigger for at least: monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups (part 6.3.1), neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current (part 6.3.2), or monitored phase undervoltage set at 0.85 pu or greater (part 6.3.3). Analog and digital triggers are used to initiate and optimize the recording of System Faults, Protective Relay performance, and abnormal System conditions by recognizing System abnormalities.

DDRs record power System behavior for incidents where the power System experiences dynamic events such as low frequency oscillations (0.1 Hz to 3 Hz), or abnormal frequency or voltage excursions. This information is necessary for comprehensive post-event analysis. The locations of DDRs can be selected with the help of time-domain simulation or small signal analysis to help identify the most critical substations where local and inter-area power System dynamics can be monitored. By combining time-domain dynamic simulation and linear based small signal analysis, critical sites can be identified for a DDR. DDRs should be well distributed across the NPCC Region. Requirement R7 requires that each Reliability Coordinator establish its area’s requirements for DDR capability that: provides a minimum of 1 DDR per 3,000 MW of peak Load (part 7.1); and records dynamic disturbance information with consideration of (part 7.2) major Load centers (part 7.2.1), major Generation clusters (part 7.2.2), major voltage sensitive areas (part 7.2.3), major transmission interfaces (part

7.2.4), major transmission junctions (part 7.2.5), Elements associated with Interconnection Reliability Operating Limits (IROLs) (part 7.2.6), and major EHV interconnections between operating Areas (part 7.2.7).

Requirement R8 requires that each Reliability Coordinator specify that DDRs installed, after the approval of this standard, function as continuous recorders. The DDRs currently available are continuous recorders.

To adequately capture System disturbance data, DDRs need certain capabilities. Requirement R9 requires that each Reliability Coordinator specify that DDRs are installed with the specific capabilities detailed in parts 9.1 through 9.3. Part 9.1 specifies that DDRs must have a minimum recording time of sixty (60) seconds per trigger event. Sixty second record lengths allow the capture of enough information to enable evaluation of System performance. Part 9.2 requires that DDRs have a minimum data sample rate of 960 samples per second and a minimum data storage rate for RMS quantities of six (6) data points per second. Available DDRs have the capability to meet and exceed this requirement. Sample rates at or above 960 samples per second will provide enough information for a thorough post event analysis. Part 9.3 specifies that each DDR shall be set to trigger for at least one of the following (based on the manufacturers' equipment capabilities): rate of change of frequency (part 9.3.1), rate of change of Power (part 9.3.2), delta frequency (recommend 20 mHz change) (part 9.3.3), and oscillation of frequency (part 9.3.4).

As previously stated, it is necessary for the equipment to capture the monitored data with enough detail to make it meaningful for post event analysis. Requirement R10 requires that each Reliability Coordinator establish requirements such that the quantities detailed in parts 10.1 through 10.5 are monitored or derived where DDRs are installed. Part 10.1 specifies that line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality. Current needs to be recorded during abnormal System events to determine overloads, System and fault impedances, transients, and System performance. It is important that the design of the input circuitry to the DDR have the current sources not affected by normal line maintenance activities to maximize the DDR's in service time. Part 10.2 specifies that bus voltages such that normal bus maintenance activities do not interfere with DDR functionality. Voltage needs to be recorded during an abnormal System event to determine System impedances, transients, and System reactive parameters. It is important that the design of the input circuitry not have the voltage sources affected by normal line maintenance activities to maximize the DDR's in service time. Part 10.3 specifies that as a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements be monitored or derived. One of the monitored voltages shall be of the same phase as the monitored current. Stability simulations assume that the post-fault response of a power System is balanced in the three phases. Therefore monitoring one phase current provides satisfactory results. Part 10.4 specifies that frequency be monitored or derived. Frequency needs to be monitored to determine the generation/load, balance/unbalance, and to record any transients. Part 10.5 specifies that real and reactive power be monitored or derived. This is a parameter that can be derived from the monitored quantities to enable an accurate analysis of System performance for abnormal events.

It is important that the RE know what data will be recorded for a System disturbance. As a result, Requirement R11 requires that each Reliability Coordinator document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the RE upon request.

The drafting team determined that the Reliability Coordinator shall be responsible for ensuring that adequate data is captured for event analysis. Requirement R12 mandates that each Reliability Coordinator specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners.

Because it is necessary to coordinate expectations for the installation and the capability of equipment, the Reliability Coordinators, Transmission Owners, and Generator Owners must discuss and implement realistic implementation schedules. That is, to ensure that all the necessary data needed to analyze an event is captured, the Reliability Coordinators, Transmission Owners, and Generator Owners must know what they are each doing so as not to install unnecessarily redundant equipment. Requirement R13 requires that each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR to acquire and install the DDR in accordance with Requirement R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule.

To ensure the that the equipment required by this standard is available and functioning properly, Requirement R14 requires that each Transmission Owner and Generator Owner establish a maintenance and testing program for stand-alone DME (equipment whose only purpose is disturbance monitoring) that includes: maintenance and testing intervals and their basis (part 14.1); a summary of maintenance and testing procedures (part 14.2); monthly verification of communication channels used for accessing records remotely (part 14.3); monthly verification of time synchronization (part 14.4); monthly verification of active analog quantities (part 14.5); verification of DDR and Digital Fault Recorder ("DFR") settings in the software every six (6) years (part 14.6); and a requirement to return failed units to service within 90 days (part 14.7). Part 14.7 further specifies that if a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.

For coordination purposes the standard drafting team designed a requirement to ensure that all appropriate parties have access to data in a timely fashion. Requirement R15 requires that each Reliability Coordinator, Transmission Owner, and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner must provide recorded disturbance data from DMEs within 30 days of receipt of the request as specified in parts 15.1 and 15.2.

To facilitate post event analysis, it is important to share information in acceptable and compatible formats to ensure accurate and timely analysis. Requirement R16 requires that each Reliability Coordinator, Transmission Owner, and Generator Owner submit the data files conforming to the format requirements in parts 16.1 through 16.3.

Finally, Requirement R17 requires that each Reliability Coordinator, Transmission Owner, and Generator Owner maintain, record and provide to the RE, upon request, specific types of data for the DMEs installed to meet this standard. This will facilitate the post event analysis.

5. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply.

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

The proposed Regional Reliability Standard establishes clear and unambiguous requirements for Transmission Owners, Generator Owners, and Reliability Coordinators within the NPCC region as discussed above. Transmission Owners, Generator Owners, and Reliability Coordinators in the NPCC region are clearly identified as the functional entities responsible for the actions specified in the requirements. The Transmission Owners and Generator Owners are assigned requirements related to the installation of DME and are responsible for ensuring that the equipment captures the specific data at the locations specified in the proposed standard. The Reliability Coordinators are assigned the responsibility of determining the DDR requirements and for coordinating these requirements with the Regional Entity as well as the Transmission Owners and Generator Owners. Additionally, all of the data generated through the disturbance monitoring performed under this standard shall be available upon request by the ERO, the RE, or other Transmission Owners or Generator Owners in an approved format.

6. Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

> Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

The proposed Regional Reliability Standard includes a Violation Risk Factor ("VRF") and Violation Severity Level ("VSL") for each requirement. The ranges of penalties for violations will be based on the applicable VRF and VSL and will be administered based on the sanctions table and supporting penalty determination process described in the FERC-approved NERC Sanction Guidelines.[14]

NPCC developed the VSLs and VRFs proposed for assignment to PRC-002-NPCC-01 following applicable NERC and FERC guidance. **Exhibit E** to this filing contains the VSL and VRF guideline analysis for PRC-002-NPCC-01.

7. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.

> Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

Each requirement of PRC-002-NPCC-01 has an associated measure of compliance that will assist those enforcing the standard in enforcing it in a consistent and non-preferential manner. The proposed measures are as follows:

M1. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Sequence of Event recording capability in accordance with 1.1 and 1.2. (R1)

M2. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 2.1 to 2.6. (R2)

M3. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability that determined the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements in accordance with R3.

M4. Each Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability for its Generating Plants at and above 200 MVA Capacity in accordance with R4.

[14] NERC Rules of Procedure Appendix 4B. Available at: http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110101.pdf.

M5. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it records for Faults, sufficient electrical quantities for each monitored Element to determine the parameters listed in 5.1 to 5.5. (R5)

M6. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 6.1 to 6.4. (R6)

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it established its area's requirements for Dynamic Disturbance Recording (DDR) capability in accordance with 7.1 and .2. (R7)

M8. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs installed after the approval of this standard function as continuous recorders. (R8)

M9. Each Reliability Coordinator shall have, and provide upon request, evidence that it developed DDR setting triggers to include the parameters listed in 9.1 to 9.3. (R9)

M10. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs monitor the Elements listed in 10.1 through 10.5. (R10)

M11. Each Reliability Coordinator shall have, and provide upon request, evidence that it documented additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10. (R11)

M12. Each Reliability Coordinator shall have, and provide upon request, evidence that it specified its DDR requirements which included the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners in the Reliability Coordinator's area. (R12)

M13. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it acquired and installed the DDRs in accordance with the specifications contained in the Reliability Coordinator's request, and a mutually agreed upon implementation schedule. (R13)

M14. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it has a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that meets the requirements in 14.1 through 14.7. (R14)

M15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided recorded disturbance data from DMEs within 30 days of the receipt of the request from the entities listed in 15.1 and 15.2. (R15)

M16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it submitted the data files in a format that meets the requirements in 16.1 through 16.3. (R16)

M17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained a record of and provided to NPCC when requested, the data on DMEs installed meeting the requirements 17.1 through 17.8. (R17)

8. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost.

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently

Regional Reliability Standard PRC-002-NPCC-01 achieves its reliability goal effectively and efficiently. The standard accomplishes the reliability goal of ensuring the installation of adequate DME to capture data for BPS events occurring in the NPCC region. By facilitating event analysis, system reliability is improved by allowing effective real time responses to events, as well as improving system operations and designs to improve system performance. The Implementation Plan for PRC-002-NPCC-01 recognizes the existence of equipment already in place. Any additional costs for the installation of required equipment are necessary to ensure that adequate disturbance monitoring equipment is in place to capture System data for event analysis. The Implementation Plan and standard also recognize that certain disturbance monitoring functions are or can be incorporated into some types of existing equipment.

9. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability.

> Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although [FERC] will give due weight to the technical expertise of the ERO, [FERC] will

> not hesitate to remand a proposed Reliability Standard if [FERC is] convinced it is not adequate to protect reliability.

This proposed Regional Reliability Standard does not reflect a "lowest common denominator" approach. PRC-002-NPCC-01 achieves its reliability goal of capturing needed data for event analysis in an efficient and effective manner. The proposed standard PRC-002-NPCC-01 builds upon the NERC Board approved standard PRC-002-1 — Define Regional Disturbance Monitoring and Reporting Requirements and the FERC approved Standard PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting by proposing requirements that are more stringent than or are not covered by the existing standards as discussed above.

10. Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability.

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

As discussed above, the proposed Implementation Plan recognizes the existence of DME already in place. Any costs incurred by the registered entities for the installation of additional equipment are necessary to ensure that adequate System data is captured for event analysis. The Implementation Plan and standard also recognize that certain disturbance monitoring functions can be incorporated into some types of existing equipment. By virtue of their electrical "size," smaller entities will incur less expenses meeting the equipment requirements of this standard than larger entities.

11. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach.

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

The proposed Regional Reliability Standard is designed on a regional basis and will only apply to the NPCC region. It is not intended to be applied throughout North America.

12. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid.

> Order No. 672 at P 332. As directed by section 215 of the FPA, [FERC] itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

This proposed Regional Reliability Standard does not cause undue negative effects on competition or restriction of the grid. Because this standard will be applied equally across the NPCC region, PRC-002-NPCC-01 will not negatively affect competition, or restrict available transmission capability within the NPCC footprint.

13. The implementation time for the proposed Reliability Standards must be reasonable.

> Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, [FERC] will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The Implementation Plan for the Regional Reliability Standard proposes a phased in implementation schedule as follows:

> Within two (2) years of FERC and Canadian entities' approvals, entities shall be 50 percent compliant at facilities required to have DME capabilities by:
>
> a. Installing Sequence of Events (SOE) capability at 50 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed)
>
> b. Installing additional SOE capability to facilities with existing SOEs such that 50 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)
>
> c. Installing Fault Recording capability at 50 percent of the facilities that previously had no Fault Recording capability (percent complete will be based on the number of facilities completed)
>
> d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 50 percent of the required capability is complete (percent complete will be based on the number of traces required)
>
> e. Installing Dynamic Disturbance Recording (DDR) capability at 50 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)
>
> f. Installing additional DDR capability to facilities with existing DDR capability such that 50 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

Within three (3) years of FERC and Canadian entities' approvals, entities shall be 75 percent compliant at facilities required to have DME capabilities by:

a. Installing SOE capability at 75 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed)

b. Installing additional SOE capability to facilities with existing SOEs such that 75 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)

c. Installing Fault Recording capability at 75 percent of the facilities that previously had no Fault Recording capability (percent complete will be based on the number of facilities completed)

d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 75 percent of the required capability is complete (percent complete will be based on the number of traces required)

e. Installing DDR capability at 75 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)

f. Installing additional DDR capability to facilities with existing DDR capability such that 75 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

Within four (4) years of FERC and Canadian entities' approvals, all (100 percent) SOE, Fault Recording, and DDR capability shall be installed to satisfy the requirements of the standard.

The information submitted by NPCC supports the implementation schedule presented.

14. The Reliability Standard development process must be open and fair.

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its [FERC]-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will

> not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by [FERC].

NPCC develops Regional Reliability Standards in accordance with **Exhibit C** (*Regional Reliability Standard Development Procedure*) of its Regional Delegation Agreement with NERC. The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NPCC considers the comments of all stakeholders and an affirmative vote of the stakeholders and the NPCC Board of Directors are both required to approve a Regional Reliability Standard for submission to NERC and FERC.

The proposed Regional Reliability Standard has been developed and approved by industry stakeholders using NPCC's *Regional Reliability Standards Development Procedure* and was approved by the NPCC Board of Directors on February 9, 2010. The standard was subsequently presented to, and approved by the NERC Board of Trustees Nov. 4, 2010. Therefore, NPCC has utilized its standard development process in good faith and in a manner that is open and fair. No commenters disagreed with the open and fair implementation of the NPCC process.

15. Proposed Reliability Standards must balance with other vital public interests.

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

Neither NERC nor NPCC believes there are competing public interests with the request for approval of this proposed Regional Reliability Standard. No comments were received that indicated the proposed standard conflicts with other vital public interests.

Therefore it is not necessary to balance this Reliability Standard against any other competing public interests.

16. Proposed Reliability Standard must not conflict with prior FERC Rules or Orders.

> Order No. 672 at P 444. A potential conflict between a Reliability Standard under development and a Transmission Organization function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission should be identified and addressed during the ERO's Reliability Standard Development Process.

The proposed PRC-002-NPCC-01 Regional Reliability Standard does not conflict with any other prior FERC Rules or Orders and adequately addresses the directives identified in FERC Order No. 693.

d. Additional Order No. 672 Criteria for Regional Reliability Standards

FERC's Order No. 672 also establishes additional criteria that a Regional Reliability Standard must satisfy: "A regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard including a regional difference that addresses matters the continent-wide Reliability Standard does not, or (2) a Regional Reliability Standard that is necessitated by a physical difference in the Bulk-Power System."[15] The proposed standard satisfies these additional criteria.

The existing NERC continent-wide standard, PRC-002-1 — Define Regional Disturbance Monitoring and Reporting Requirements,[16] applies only to Regional Reliability Organizations (now known as Regional Entities). The proposed standard, PRC-002-NPCC-01, establishes more stringent installation requirements for sequence of event recorders by identifying specific installation locations, and the equipment to be

[15] Order No. 672 at P 291.
[16] NERC Standard PRC-002-1 — Define Regional Disturbance Monitoring and Reporting.

monitored in Requirement R1. The proposed standard also establishes more stringent installation requirements for Fault recording capability by identifying specific transmission and generation facilities where the equipment should be installed in accordance with Requirement R2 through R6. While the NPCC Regional Reliability Standard mirrors the NERC standard for identifying DDR quantities, the proposed standard also specifies DDR equipment triggering options and establishes reporting requirements for the Region.

The proposed standard, PRC-002-NPCC-01, establishes requirements that specify the locations where Transmission Owners and Generator Owners must install DME. The FERC-approved PRC-018-1 standard does not specify the locations but does require the installation of equipment according to the RRO requirements. The proposed standard also adds the Reliability Coordinator as a functional entity. Finally, the proposed PRC-002-NPCC-01 standard is more stringent than the continent-wide standard because it adds monthly verification steps and requires verification of DDR and DFR settings in the software every six years while the continent-wide standard does not.

Furthermore PRC-002-1 is not enforceable. In Order No. 693 the Commission neither remanded nor approved the standard but deemed it as a "fill-in-the blank" standard.[17] Because of this, NPCC recognized a reliability gap relating to Disturbance monitoring and reporting and developed PRC-002-NPCC-01 to fill this gap.

[17] Order No. 693 at P 1450, 1455. PRC-018-1 is mandatory and enforceable.

V. SUMMARY OF THE REGIONAL RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

NERC Evaluation: On May 14, 2010, NPCC submitted the proposed Regional Reliability Standard for evaluation and approval to NERC in accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure*[18] that was approved by NERC's Regional Reliability Standards Working Group. NERC provided its evaluation of the proposed PRC-002-NPCC-01 standard to NPCC on July 3, 2010, included as **Exhibit C**, after NERC concluded its 45-day posting of the standard. In this report, NERC expressed several concerns regarding the proposed Regional Reliability Standard. These concerns pertained to the use of certain terms in the proposed standard; to the development of Measures including examples of evidence; and proposed modifications to the Violation Severity Levels necessary to comport with FERC's VSL Guidelines. The VSL proposals also resulted in changes to the associated requirements in the standard. During the evaluation process, NERC also identified several additional concerns in the proposed standard that NPCC should consider addressing in a future revision of the standard, primarily concerning the development structure of the requirements. In response to NERC's concerns, NPCC modified the proposed VSLs to comport with FERC's VSL Guidelines and elected to consider the additional NERC comments during a future revision of the standard.

Key Issues: During the development of the proposed standard, the drafting team encountered three key issues. The industry expressed concern over: 1) the development of a continent-wide standard by NERC to address this issue; 2) the size of affected generating units/plants; and 3) the definition of Bulk Electric System.

[18] Regional Reliability Standards Evaluation Procedure, Version 1 (2009). Available at: http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Evaluation_Procedure.pdf.

The development of the proposed standard began in mid-2008 and was intended to complement the ongoing work at NERC revising PRC-002-1 and PRC-018-1 in *Project 2007-11: Disturbance Monitoring*. The proposed standard establishes requirements that are currently not covered by either the Board approved standard, PRC-002-1 — Define Regional Disturbance Monitoring and Reporting Requirements, or PRC-018-1 — Disturbance Monitoring Equipment Installation and Data Reporting. The Regional Reliability Standard was initiated with the intention of addressing a reliability need to specify regional requirements for the installation of Disturbance Monitoring Equipment. Furthermore, the proposed standard addresses a specific recommendation from the August 14, 2003 Blackout Final NERC Report.[19]

While the work with *Project 2007-11: Disturbance Monitoring* is in progress, it was not anticipated for completion until after the proposed PRC-002-NPCC-01 standard's projected completion date. As a result, the proposed standard both addresses the recommendations above and relieves the reliability need to establish DME requirements currently not covered in the existing NERC standards.

The second key issue encountered related to the size of generating units/plants in the proposed standard. Requirement R1 part 1.1 specifies that SOE capability:

> Be provided by Generator Owners at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.
>
> Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit

[19] Recommendation 28, "Require use of time-synchronized data recorders," *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force (2004) at p.162. Available at: http://www.nerc.com/docs/docs/blackout/ch7-10.pdf.

> results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.

As discussed above, the 300MW radial load was selected based on the engineering judgment and operating experience of NPCC members and is consistent with NPCC document A-15 *Disturbance Monitoring Equipment Criteria*, and the possibility of the loss of 300MW escalating to a wider area disturbance. Additionally, the drafting team used as a baseline the event that tripping of a fully loaded 1200 Amp 138kV circuit breaker would drop 300MW of load. Ideally, every generator registered in NPCC should be monitored. Because of the relative contributions of the smaller and larger generators to System events, it was decided that monitoring the larger units would provide the more important and useful information for event analysis.

The third key issue identified during the development of the standard was the definition of the BES. The purpose section of the proposed standard states that: "All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements." Industry commenters expressed concern that this would lead to confusion because NPCC uses the defined term "Bulk Power System." NPCC resolved the concern by noting that FERC, in its Order No. 693, approved NERC's definition of Bulk Electric System, and using it as the basis for applicability of PRC-002-NPCC-01 would be consistent with NERC and other regions' standards as well as Section 215 of the FPA.

Violation Risk Factors and Violation Severity Levels

The proposed Regional Reliability Standard contains both VRFs and VSLs. The VRFs and VSLs are assigned to the main requirements in the standard. The VRFs and

VSLs for this standard were developed and reviewed for consistency with NERC and FERC guidelines.[20] Analyses of the assigned VRFs and VSLs to this standard are included in **Exhibit E**.

VI. CONCLUSION

For the reasons stated above, NERC respectfully requests that FERC approve the proposed PRC-002-NPCC-01 Regional Reliability Standard, the associated proposed definitions, and the associated Implementation Plan included in **Exhibit A** to this filing in accordance with Section 215(d)(1) of the FPA and Part 39.5 of FERC's regulations. NERC requests that these approvals be made effective in accordance with the Implementation Plan for PRC-002-NPCC-01 included in **Exhibit A** to this filing.

Respectfully submitted,

/s/ Andrew M. Dressel

Gerald W. Cauley
President and Chief Executive Officer
David N. Cook
Senior Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Holly A. Hawkins
Assistant General Counsel for Critical Infrastructure and Standards
Andrew M. Dressel
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W. Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
holly.hawkins.@nerc.net
andrew.dressel@nerc.net

[20] *See Order on Violation Risk Factors*, 119 FERC ¶ 61,145 (2007) and *Order on Violation Severity Levels Proposed by the Electric Reliability Organization*, 123 FERC ¶ 61,284 (2008).

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 31st day of May, 2011.

<u>*/s/ Andrew M. Dressel*</u>
Andrew M. Dressel
Attorney for North American Electric Reliability Corporation

Exhibit A

PRC-002-NPCC-01 — Disturbance Monitoring Regional Reliability Standard and Implementation Plan Proposed for Approval

A. Introduction

1. **Title:** **Disturbance Monitoring**
2. **Number:** PRC-002-NPCC-01
3. **Purpose:** Ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
   - **4.3.** Reliability Coordinator
5. **(Proposed) Effective Date:** To be established.

B. Requirements

R1. Each Transmission Owner and Generator Owner shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of Fault recording equipment. This capability shall: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

1.1 Be provided at all substations and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.

Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.

1.2 Monitor the following at each location listed in 1.1:

1.2.1 Transmission and Generator circuit breaker positions

1.2.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.2.1.

1.2.3 Teleprotection keying and receive

R2. Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities where Fault recording equipment is required to be installed as per R3: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

2.1 All transmission lines.

2.2 Autotransformers or phase-shifters connected to busses.

2.3 Shunt capacitors, shunt reactors.

2.4 Individual generator line interconnections.

2.5 Dynamic VAR Devices.

2.6 HVDC terminals.

R3. Each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R4. Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 200 MVA Capacity and connected through a generator step up (GSU) transformer to a Bulk Electric System Element unless Fault recording capability is already provided by the Transmission Owner. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R5. Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

5.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)

5.2 Three phase currents and neutral currents.

5.3 Polarizing currents and voltages, if used.

5.4 Frequency.

5.5 Real and reactive power.

R6. Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

6.1 Each Fault recorder record duration shall be a minimum of one (1) second.

6.2 Each Fault recorder shall have a minimum recording rate of 16 samples per cycle

6.3 Each Fault recorder shall be set to trigger for at least the following:

6.3.1 Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups.

6.3.2 Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current.

6.3.3 Monitored phase undervoltage set at 0.85 pu or greater.

6.4 Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.

R7. Each Reliability Coordinator shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

7.1 Provides a minimum of 1 DDR per 3,000 MW of peak Load.

7.2 Records dynamic disturbance information with consideration of the following facilities/locations:

7.2.1 Major Load centers.

7.2.2 Major Generation clusters.

7.2.3 Major voltage sensitive areas.

7.2.4 Major transmission interfaces.

7.2.5 Major transmission junctions.

7.2.6 Elements associated with Interconnection Reliability Operating Limits (IROLs).

7.2.7 Major EHV interconnections between operating areas.

R8. Each Reliability Coordinator shall specify that DDRs installed, after the approval of this standard, function as continuous recorders. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R9. Each Reliability Coordinator shall specify that DDRs are installed with the following capabilities: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

9.1 A minimum recording time of sixty (60) seconds per trigger event.

9.2 A minimum data sample rate of 960 samples per second, and a minimum data storage rate for RMS quantities of six (6) data points per second.

9.3 Each DDR shall be set to trigger for at least one of the following (based on manufacturers' equipment capabilities):

9.3.1 Rate of change of Frequency.

9.3.2 Rate of change of Power.

9.3.3 Delta Frequency (recommend 20 mHz change).

9.3.4 Oscillation of Frequency.

R10. Each Reliability Coordinator shall establish requirements such that the following quantities are monitored or derived where DDRs are installed: *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

10.1 Line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality.

10.2 Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality.

10.3 As a minimum, one phase current per monitored Element and two phase-to-neutral voltages of different Elements. One of the monitored voltages shall be of the same phase as the monitored current.

10.4 Frequency.

10.5 Real and reactive power.

R11. Each Reliability Coordinator shall document additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10, and report this to the Regional Entity (RE) upon request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

R12. Each Reliability Coordinator shall specify its DDR requirements including the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R13. Each Transmission Owner and Generator Owner that receives a request from the Reliability Coordinator to install a DDR shall acquire and install the DDR in accordance with R12. Reliability Coordinators, Transmission Owners, and Generator Owners shall mutually agree on an implementation schedule. *[Violation Risk Factor: Medium] [Time Horizon: Planning and Operations Planning]*

R14. Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for stand alone DME (equipment whose only purpose is disturbance monitoring) that includes: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

14.1 Maintenance and testing intervals and their basis.

14.2 Summary of maintenance and testing procedures.

14.3 Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)).

14.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).

14.5 Monthly verification of active analog quantities.

14.6 Verification of DDR and DFR settings in the software every six (6) years.

14.7 A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days the owner shall keep a record of efforts aimed at restoring the DME to service.

R15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each Reliability Coordinator, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

15.1 NERC, Regional Entity, Reliability Coordinator.

15.2 Request from other Transmission Owners, Generator Owners within NPCC.

R16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

16.1 The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111.

16.2 Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232.

16.3 Fault Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station name, date, time resolved to milliseconds, SOE point name, status.

R17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall maintain, record and provide to the Regional Entity (RE), upon request, the following data on the DMEs installed to meet this standard: *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

17.1 Type of DME.

17.2 Make and model of equipment.

17.3 Installation location.

17.4 Operational Status.

17.5 Date last tested.

17.6 Monitored Elements.

17.7 All identified channels.

17.8 Monitored electrical quantities.

C. Measures

M1. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Sequence of Event recording capability in accordance with 1.1 and 1.2. (R1)

M2. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 2.1 to 2.6. (R2)

M3. Each Transmission Owner shall have, and provide upon request, evidence that it provided Fault recording capability that determined the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements in accordance with R3.

M4. Each Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability for its Generating Plants at and above 200 MVA Capacity in accordance with R4.

M5. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it records for Faults, sufficient electrical quantities for each monitored Element to determine the parameters listed in 5.1 to 5.5. (R5)

M6. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided Fault recording capability in accordance with 6.1 to 6.4. (R6)

M7. Each Reliability Coordinator shall have, and provide upon request, evidence that it established its area’s requirements for Dynamic Disturbance Recording (DDR) capability in accordance with 7.1 and .2. (R7)

M8. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs installed after the approval of this standard function as continuous recorders. (R8)

M9. Each Reliability Coordinator shall have, and provide upon request, evidence that it developed DDR setting triggers to include the parameters listed in 9.1 to 9.3. (R9)

M10. Each Reliability Coordinator shall have, and provide upon request, evidence that DDRs monitor the Elements listed in 10.1 through 10.5. (R10)

M11. Each Reliability Coordinator shall have, and provide upon request, evidence that it documented additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10. (R11)

M12. Each Reliability Coordinator shall have, and provide upon request, evidence that it specified its DDR requirements which included the DDR setting triggers established in R9 to the Transmission Owners and Generator Owners in the Reliability Coordinator’s area. (R12)

M13. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it acquired and installed the DDRs in accordance with the specifications contained in the Reliability Coordinator’s request, and a mutually agreed upon implementation schedule. (R13)

M14. Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it has a maintenance and testing program for stand alone DME

(equipment whose only purpose is disturbance monitoring) that meets the requirements in 14.1 through 14.7. (R14)

M15. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it provided recorded disturbance data from DMEs within 30 days of the receipt of the request from the entities listed in 15.1 and 15.2. (R15)

M16. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it submitted the data files in a format that meets the requirements in 16.1 through 16.3. (R16)

M17. Each Reliability Coordinator, Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained a record of and provided to NPCC when requested, the data on DMEs installed meeting the requirements 17.1 through 17.8. (R17)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Transmission Owner and Generator Owner shall keep evidences for three calendar years for Measures 1, 5, 6, 13, 16 and 17.

The Transmission Owner shall keep evidence for three years for Measures 2 and 3.

The Generator Owner shall keep evidence for three years for Measure 4.

The Reliability Coordinator shall keep evidence for three years for Measures 7, 8, 9, 10, 11, 12, 16 and 17.

The Transmission Owner and Generator Owner shall keep evidences for twenty-four calendar months for Measures 14 and 15.

The Reliability Coordinator shall keep evidence for twenty-four calendar months for Measure 15.

If a Transmission Owner, Generator Owner or Reliability Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit and all subsequent record.

1.4. Compliance Monitoring and Assessment Processes

- Self-Certifications
- Spot Checking
- Compliance Audits
- Self-Reporting
- Compliance Violation Investigations
- Complaints

1.5. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1 The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed…	Up to and including 10% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 10% and up to and including 20% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 20% and up to and including 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.	More than 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
R2 The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed…	Up to and including 10% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 10% and up to and including 20% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 20% and up to and including 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.	More than 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
R3 The Transmission Owner failed to provide…	Not applicable.	Not applicable.	Not applicable.	Fault recording capability that determines the current zero time for loss of transmission Elements.
R4 The Generator Owner failed to provide Fault recording capability at…	Up to and including 10% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is	More than 10% and up to and including 20% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 20% and up to 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.	More than 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.

	inadequate.			
R5 The Transmission Owner or Generator Owner failed to record for the Faults…	Up to and including 10% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 10% and up to and including 20% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 20% and up to and including 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.	More than 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
R6 The Transmission Owner or Generator Owner failed …	To provide Fault recording capability for up to and including 10% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for up to 2 locations.	To provide Fault recording capability for more than 10% and up to and including 20% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than two (2) and up to and including five (5) locations.	To provide Fault recording capability for more than 20% and up to and including 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than five (5) and up to and including ten (10) locations.	To provide Fault recording capability for more than 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than ten (10) locations.
R7 The Reliability Coordinator failed to establish	Up to and including 10% of the required DDR coverage	More than 10% and up to and including 20% of the required DDR coverage for	More than 20% and up to and including 30% of the required DDR coverage for	More than 30% of the required DDR coverage for its area as per 7.1 and 7.2.

its area's requirements for…	for its area as per 7.1and 7.2.	its area as per 7.1 and 7.2.	its area as per 7.1 and 7.2.	
R8 The Reliability Coordinator failed to specify that DDRs installed…	Not applicable.	Not applicable.	Not applicable.	Function as continuous recorders.
R9 The Reliability Coordinator failed to specify that DDRs are installed without…	Not applicable.	Not applicable.	Not applicable.	The capabilities listed in 9.1 through 9.3.
R10 The Reliability Coordinator failed to ensure that the quantities listed in 10.1 through 10.5 are monitored or derived…	Not applicable.	Not applicable.	Not applicable.	Where DDRs are installed.
R11 The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for…	Up to two (2) facilities within the Reliability Coordinator's area that have a DDR.	More than two (2) and up to five (5) facilities within the Reliability Coordinator's area that have a DDR.	More than five (5) and up to ten (10) facilities within the Reliability Coordinator's area that have a DDR.	More than ten (10) facilities within the Reliability Coordinator's area that have a DDR.
R12 The Reliability Coordinator failed to specify to the Transmission Owners and Generator Owners its DDR requirements	Not applicable.	Not applicable.	Not applicable.	Established setting triggers.

including the DDR setting triggers established in R9 but missed…				
R13 The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for…	Up to and including 10% of the requirement set of the Reliability Coordinator's request to install DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 10% and up to 20% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 20% and up to 30% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.	More than 30% of the requirement set requested by the Reliability Coordinator and installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR OR The Reliability Coordinator, Transmission Owners, and Generator Owners failed to mutually agree on an implementation schedule.
R14 The Transmission Owner or Generator Owner…	Established a maintenance and testing program for stand alone DME but provided incomplete data for any one (1) of 14.1 through 14.7.	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than one (1) and up to and including three (3) of 14.1 through 14.7.	Established a maintenance and testing program for stand alone DME but provided incomplete data for more than three (3) and up to and including six (6) of 14.1 through 14.7.	Did not establish any maintenance and testing program for DME; OR The Transmission Owner or Generator Owner established a maintenance and testing program for DME but did not provide any data that meets all of 14.1 through 14.7.
R15 The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for…	Up to and including fifteen (15) days in meeting the requests of an entity, or entities in 15.1, or 15.2.	More than fifteen (15) days but less than and including thirty (30) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than 30 days but less than and including forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.	More than forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.

R16 The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit…	Up to and including two (2) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than two (2) and up to and including five (5) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than five (5) and up to and including ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.	More than ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
R17 The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request…	Up to and including two (2) of the items in 17.1 through 17.8.	More than two (2) and up to and including four (4) of the items in 17.1 to 17.8.	More than four (4) and up to and including six (6) of the items in 17.1 through 17.8.	More than six (6) of the items in 17.1 through 17.8.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking

Standard Development Roadmap

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

Development Steps Completed:

1. RSAR forwarded to the RSC for review July 22, 2008.
2. RSC authorized the SAR to be forwarded to the RCC for Task Force assignment Aug. 21, 2008.
3. RCC to appointed TFSP as the Lead Task Force Sept. 4, 2008.
4. First draft posted on the NPCC website Nov. 5, 2008 for 45 day comment period.
5. Second draft posted on the NPCC website June 2, 2009 for 45 day comment period.
6. Third draft posted for Pre-Ballot Review Nov. 24, 2009.
7. Ballot began Dec. 17, 2009; Standard approved by NPCC Membership Jan. 6, 2010.
8. Presented to, and approved by the NPCC Board of Directors Feb. 9, 2010.

Description of Current Draft:

This is the draft of the standard approved by the NPCC Board of Directors.

Future Development Plan:

Anticipated Action	Date
Consolidate comments--submit to TFSP	May 28, 2009
Post response to comments, and second version of standard	June 1, 2009
Post response to comments, and third version of standard	Sept. 9, 2009
For Pre-Ballot Review	Nov. 24, 2009
Posting of Notification of Ballot	Dec. 2, 2009
Ballot period begins	Dec. 17, 2009
NPCC Membership approval	Jan. 6, 2010
NPCC Board of Directors approval	Feb. 9, 2010
NERC approval	Nov. 4, 2010

Definitions of Terms Used in Standard

This section includes all newly defined terms used in the proposed Standard. Terms already defined in the NERC glossaries are not repeated here. The new definitions listed below become approved when the proposed Standard is approved. The terms will be listed and defined in the NPCC Section of the NERC Glossary. The NPCC Section will list terms specific to the NPCC region.

In the Standard, defined terms are indicated with their first letters capitalized.

Current Zero Time: The time of the final current zero on the last phase to interrupt.

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

Implementation Plan for PRC-002-NPCC-01 Disturbance Monitoring

Background

In developing the Implementation Plan for PRC-002-NPCC-01 the Standard Drafting Team considered the following:

1. The requirements listed in this Regional Standard are intended to cover all aspects of the utilization of Disturbance Monitoring equipment. The intent of the Standard is to be more stringent than the continent wide Standard under development at NERC. After the approved NERC continent wide Standard is issued, PRC-002-NPCC-01 will be revisited to eliminate any redundancies.

2. The refueling outage schedules of nuclear plants will be considered when determining their compliance.

3. Any implementation plan will be impacted by the resource availability and approval processes of the Reliability Coordinators, Transmission Owners, and Generator Owners.

4. It is assumed the Reliability Coordinators have already established their DDR needs. If not, “time zero” will be after the Reliability Coordinator issues the locations and needs for additional DDR equipment.

Effective Dates

1. Within two (2) years of FERC and Canadian entities’ approvals, entities shall be 50 percent compliant at facilities required to have DME capabilities by:
   a. Installing Sequence of Events (SOE) capability at 50 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed
   b. Installing additional SOE capability to facilities with existing SOEs such that 50 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)
   c. Installing Fault Recording capability at 50 percent of the facilities that previously had no Fault Recording capability (percent complete will be based on the number of facilities completed)
   d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 50 percent of the required capability is complete (percent complete will be based on the number of traces required)
   e. Installing Dynamic Disturbance Recording (DDR) capability at 50 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)
   f. Installing additional DDR capability to facilities with existing DDR capability such that 50 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

2. Within three (3) years of FERC and Canadian entities’ approvals, entities shall be 75 percent compliant at facilities required to have DME capabilities by:

Approved by NPCC Membership Jan. 6, 2010
Board of Directors Feb. 9, 2010
Approved by NERC Board of Trustees Nov. 4, 2010

a. Installing SOE capability at 75 percent of the facilities that previously had no SOE capability (percent complete will be based on the number of facilities completed)
b. Installing additional SOE capability to facilities with existing SOEs such that 75 percent of the total required capability is complete (percent complete will be based on the number of SOE points required)
c. Installing Fault Recording capability at 75 percent of the facilities that previously had no Fault Recording capability (percent complete will be based on the number of facilities completed)
d. Installing additional Fault Recording capability to facilities with existing Fault Recording capability such that 75 percent of the required capability is complete (percent complete will be based on the number of traces required)
e. Installing DDR capability at 75 percent of the facilities that previously had no DDR capability (percent complete will be based on the number of facilities completed versus those required by the Reliability Coordinator)
f. Installing additional DDR capability to facilities with existing DDR capability such that 75 percent of the required capability is complete (percent complete will be based on the number of elements as required by the Reliability Coordinator)

3. Within four (4) years of FERC and Canadian entities' approvals, all (100 percent) SOE, Fault Recording, and DDR capability shall be installed to satisfy the requirements of this Standard.

Reference

NPCC Criteria:
A-5 Bulk Power System Protection Criteria
A-7 NPCC Glossary of Terms
A-10 Classification of Bulk Power System Elements
A-15 Disturbance Monitoring Equipment Criteria

NPCC Guides:
B-26 Guide for Application of Disturbance Recording Equipment
B-28 Draft Guideline for Generator Sequence of Event Monitoring
SP-6 Synchronized Event Data Reporting

A NPCC Directory will be developed for Disturbance Monitoring. It will contain supporting information and details from the Criteria and Guides that are not incorporated in the Standard.

Approved by NPCC Membership Jan. 6, 2010
Board of Directors Feb. 9, 2010
Approved by NERC Board of Trustees Nov. 4, 2010

Exhibit B

The NERC Board of Trustees' Resolution on the PRC-002-NPCC-01 — Disturbance Monitoring Regional Reliability Standard

(4) EOP-003-1 — Load Shedding Plans.

FURTHER RESOLVED, that NERC Staff shall make the appropriate filings with ERO governmental authorities.

NPCC Regional Disturbance Monitoring Standard
On motion of Paul Barber, the board approved the following resolutions:

RESOLVED, that the Board approves the proposed regional reliability standard and associated defined terms to be applicable only within the NPCC Region:

(1) Regional Reliability Standard PRC-002-NPCC-01 — Disturbance Monitoring;

(2) Regional definition for the term “Current Zero Time”;

(3) Regional definition for the term “Generating Plant”;

FURTHER RESOLVED, that NERC Staff shall make the appropriate filings with ERO governmental authorities.

Available Transfer Capability Violation Risk Factors
On motion of Gerry Cauley, the board approved the following resolutions:

RESOLVED, that the board approves the proposed Violation Risk Factors for the following standards:

(1) MOD-001-1 — Available Transmission System Capability;

(2) MOD-004-1 — Capacity Benefit Margin;

(3) MOD-008-1 — Transmission Reliability Margin Calculation Methodology;

(4) MOD-028-1 — Area Interchange Methodology;

(5) MOD-029-1 — Rated System Path Methodology;

(6) MOD-030-2 — Flowgate Methodology.

FURTHER RESOLVED, that NERC Staff shall make the appropriate filings with ERO governmental authorities.

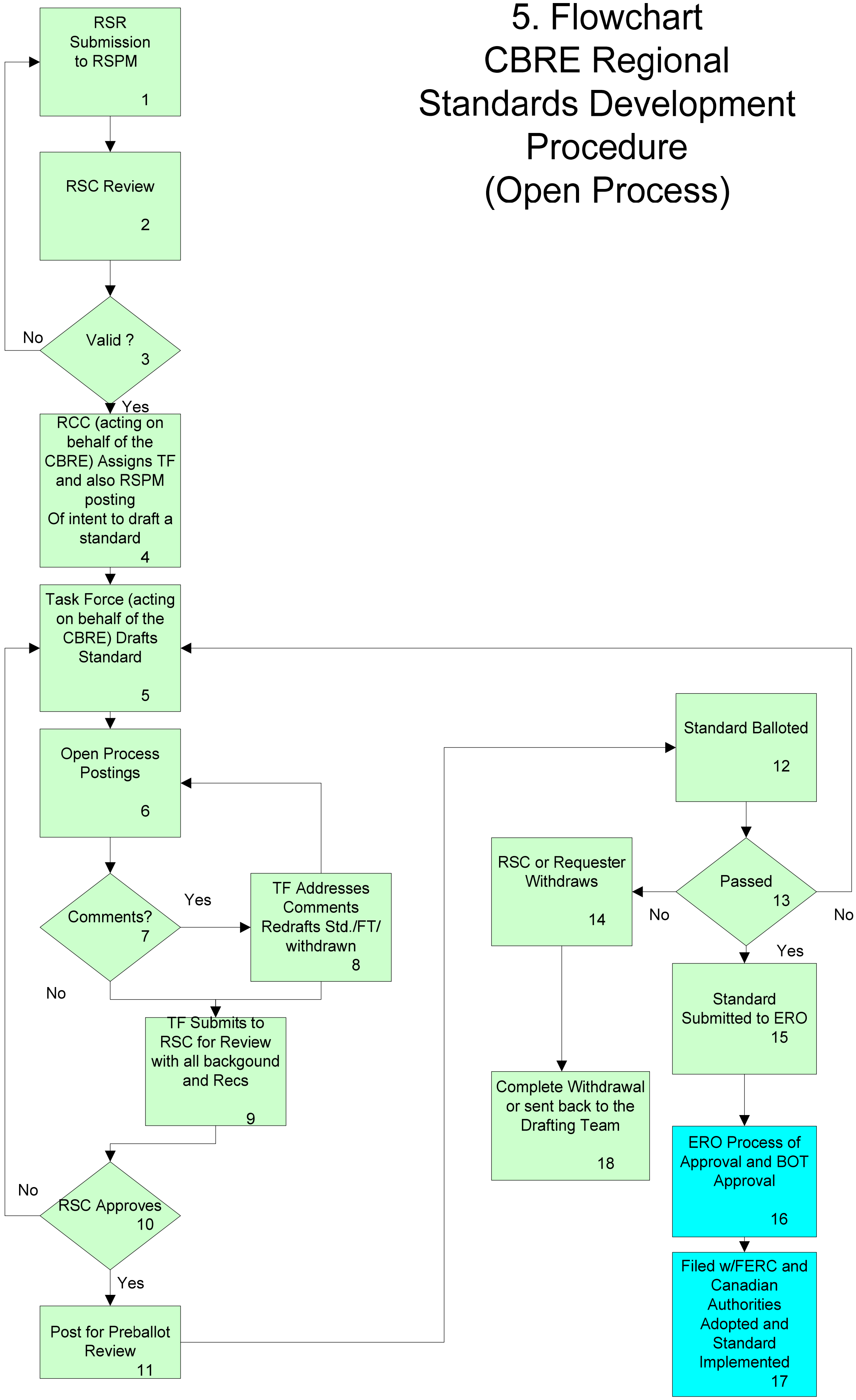
Reliability Standards Interpretations
Mr. Schrayshuen reviewed the Reliability Standards Interpretations and presented the following items for board action:

- Agenda Item 12a: Interpretation of EOP-001-0—Emergency Operations Planning, Requirement R1
- Agenda Item 12b: Interpretation of EOP-001-1 and EOP-001-2—Emergency Operations Planning, Requirement R2.2

Exhibit C

Record of Development of Proposed PRC-002-NPCC-01 Disturbance Monitoring Reliability Standard

5. Flowchart CBRE Regional Standards Development Procedure (Open Process)



NPCC First Posting Comments

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
General Comment	What is the Implementation Plan to install any required DME? Will its provisions be consistent with PRC-018? Greg Mason, Dynegy	The Implementation Plan is under review. It is intended for its provisions to be consistent with PRC-018-1. Note that NERC Project 2007-11 Disturbance Monitoring and Reporting Requirements is to produce PRC-002-2 which will replace PRC-002-1 and PRC-018-1.
General Comment	Change RRO to Regional Entity. Rick White, Northeast Utilities	Change incorporated.
Definitions of Terms Used in Standard	"Telepotection" should be "Teleprotection". Dan Rochester, IESO	Corrected.
A3	The statement "Ensure adequate provision of equipment…" does not seem to convey the actual goal of NERC PRC 002 (…establish requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of Disturbance data to facilitate analyses of events and verify system models.) Suggested rewording: Ensure that adequate Disturbance data is available to facilitate Bulk Power System event analyses and verification of system models. In addition, verification of system models based on Disturbance data is a relatively unknown area. Does the team have particular applications in mind? For example, verification of generators and generator controls models using system disturbance data would require DDRs that monitor individual units. Or, is this indication of intent to consider emerging PMU systems in this standard? Vlad Stanisic, Ontario Power Generation	The wording of the Purpose was changed. The intent of this Standard is to require the minimum Disturbance Monitoring Equipment installations necessary to adequately do post disturbance analyses with what is available today. Should PMUs prove to be a good disturbance analysis tool, this Standard can be revised in the future.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R1.1	As written this Requirement would seem to require installation SOE recording capability at **all** "generating units above 50 MW Capacity, and at generating plants above 300 MW Capacity" regardless of their connection voltage or connection location. This level of SOE recording capability for generators is not required for system reliability. Similar to Requirement 1.1 for "bulk power substations", this Requirement should be modified to only include generators connected to a Bulk Power System element. Greg Mason, Dynegy	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 50MVA and plants above 300MVA, regardless of their connections to the power system, in the requirement to have SOE capability. Unit capacity changed from MW to MVA.
R1.1	If these requirements remain, suggest increasing the generation threshold to 250MW for a single unit and 1000MW for Plant total. Greg Mason, Dynegy	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 50MVA and plants above 300MVA, regardless of their connections to the power system, in the requirement to have SOE capability. Unit capacity changed from MW to MVA.
R1.1	Recommend increasing the generating units level to 250MW for single units and 750MW for aggregated site totals. Mike Sonnelitter, FPL/NextEra Energy	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 50MVA and plants above 300MVA. Unit capacity changed from MW to MVA.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R1.1	A wind farm greater than 50MW should be considered a “generating unit” for this requirement. Robert Creighton, Nova Scotia Power Incorporated	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 50MVA and plants above 300MVA. Unit capacity changed from MW to MVA.
R1.1	**R1.1.** Be provided at all bulk power system facilities including transmission and generating stations Vlad Stanisic, Ontario Power Generation	The Drafting Team feels that for disturbance reconstruction it is important to consider the status of units down to 50MVA, and plants 300MVA.
R1.2	Consider also monitoring bus-tie and bus-section circuit breakers. This would avoid potential gaps in data that may arise if for example a bus zone protection scheme operates. Dan Rochester, IESO	The circuit breakers mentioned in the comment are already included in the Standard. Refer to R1.2.1.
R1.2.1	What is the intent of this requirement? If it is to obtain information on any device that disconnects the generator from the system, then perhaps it should include both high and low side breakers. Mike Sonnelitter, FPL/NextEra Energy	The intent of this Requirement is to include all Bulk Power System breakers, which includes both low and high side breakers.
R1.2.1	For consistency with R2.1. Proposed Revision: Insert “line” after “Transmission”. Dan Rochester, IESO	The intent of R1.2.1 is to include breakers associated with all transmission system elements. The Drafting Team feels that no revision is necessary.

Comments Received--PRC-002-NPCC-01

Requirement No.	**Comment**	**Response**
R1.2.2	Please define “protection groups”. Mike Sonnelitter, FPL/NextEra Energy	Protection Group is defined in the NPCC Glossary as: “A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.”
R1.2.2	Is it necessary to monitor protection groups for load-serving transformers? For capacitor banks less than 345kV? “all protection groups” should be better defined by relay type. Rick White, Northeast Utilities	It is necessary to monitor Protection Groups for load-serving transformers because of the impacts of their operations to the transmission system. The Protection Group definition in NPCC A-7 is adequate for the purpose of this Standard.
R1.2.2	**R1.2.2.** Protective Relay tripping for BPS equipment protection groups Vlad Stanisic, Ontario Power Generation	Wording changed.
R1.2.3	The above requirement may have to be separated into two, one for TOs and one for GOs. There is inherent difference in requirements for sequence of events monitoring emanating from the specifics of Transmission and Generation facilities. Vlad Stanisic, Ontario Power Generation	This Requirement will not have to be separated into two parts. The equipment as described is applicable to the transmission system and generating facilities.
R2.3	Is there any value in including a minimum shunt capacitor size to cater for “important” capacitors at voltages lower than 345 kV? Proposed Revision: “Shunt capacitors 345 kV and above and shunt capacitors larger than XXX MVAr” Dan Rochester, IESO	All shunt capacitors connected to a BPS Station will require monitoring. For the purposes of this Standard the capacitor bank size is not a factor.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R2.4	What size generator, or where connected (at BPS busses?)? Rick White, Northeast Utilities	Requirements R4 and R6 have been revised and address this comment.
R2.5	Does this refer to devices BPS busses? (We have a DVAR unit at 13.8kV at a non-BPS facility.) Rick White, Northeast Utilities	Refer to the wording in Requirement R3. All dynamic VAR devices connected to BPS busses must have fault recording capability.
R3	This was a definition of current zero. The capability is inherent in monitoring currents of elements. Should not be a requirement within the standard. Rick White, Northeast Utilities	Current zero time has been moved to the **Definitions of Terms Used in Standard page.**
R4	If these requirements remain, suggest increasing the generation threshold to 250MW for a single unit and 1000MW for Plant total. Greg Mason, Dynegy	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 200MVA. Requirement changed to include those units connected to a Bulk Power System element. The requirement was rewritten to ensure that there is no unnecessary duplication in the installation of fault recording equipment. Unit capacity changed from MW to MVA. Refer to R5 in the Standard for the quantities that need to be recorded.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R4	As written this Requirement would seem to require installation fault recording capability at **all** “generating units above 200 MW Capacity” regardless of their connection voltage or connection location. Fault recording capability at the generator would seem to be of little benefit in analyzing BPS faults and this provision should either (1) be eliminated from this Standard (2) be modified to only include generators connected to a Bulk Power element. Greg Mason, Dynegy	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 200MVA. Requirement changed to include those units connected to a Bulk Power System element. The requirement was rewritten to ensure that there is no unnecessary duplication in the installation of fault recording equipment. Unit capacity changed from MW to MVA. Refer to R5 in the Standard for the quantities that need to be recorded.
R4	Is it the intent of the Standard to require the Generation Owner to install fault recording devices at the plant as well as the interconnected substation that is typically owned by the Transmission Owner? If so, why? Greg Mason, Dynegy	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 200MVA. Requirement changed to include those units connected to a Bulk Power System element. The requirement was rewritten to ensure that there is no unnecessary duplication in the installation of fault recording equipment. Unit capacity changed from MW to MVA. Refer to R5 in the Standard for the quantities that need to be recorded.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R4	If this Requirement remains, what equipment/values at the plant need to be monitored? Why would anything other than generator step up transformer quantities be required? If generator step up transformer values can be obtained from the "generator interconnections" (R2.4), then why would it be necessary to install fault recording capability at the unit/plant? Greg Mason, Dynegy	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 200MVA. Requirement changed to include those units connected to a Bulk Power System element. The requirement was rewritten to ensure that there is no unnecessary duplication in the installation of fault recording equipment. Unit capacity changed from MW to MVA. Refer to R5 in the Standard for the quantities that need to be recorded.
R4	Recommend increasing the generating units level to 250MW for single units and 750MW for aggregated site totals. Mike Sonnelitter, FPL/NextEra Energy	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 200MVA. Unit capacity changed from MW to MVA.
R4	Define fault types for "fault recording". Rick White, Northeast Utilities	All electrical faults (involving or not involving ground) including and beyond generator stators will be detected by the fault recording equipment.
R4	DFR capability for generating units (regardless of their size) is of little significance in analyzing BPS faults and should not be a subject of this standard. It should be left to the discretion of particular jurisdictions (areas) and GOs to determine particular local requirements. Vlad Stanisic, Ontario Power Generation	Because of the importance of generation to system reliability and for post disturbance analysis, it is important to include units above 200MVA.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R5	Are the electrical quantities referred to, instantaneous, RMS or both? Is the frequency to be calculated over 1 cycle or ½-cycle? Dan Rochester, IESO	The Standard will not prescribe how the quantity is recorded. It is important that the method is identified or understood (manufacturers may use different methods). The requirement stipulates that the recorder provide enough information for the user to determine the frequency.
R5.5	Why record power for faults? If you can determine 5.1 and 5.2, you can determine active and reactive power. Rick White, Northeast Utilities	This inclusion is consistent with NERC Standards. The Requirement specifies that you be able to determine, not necessarily record the quantities.
R6.1	The technical requirements for fault duration as well as, the requirement to have a minimum recording rate of 16 samples per cycle will not allow the use of existing solid state relays that currently have fault recording capability. The increased costs associated with having to upgrade existing equipment to meet a more stringent recording requirement (one that may not necessarily provide a distinct benefit over the existing equipment) are significant, and the upgrade itself may not be necessary. Mike Sonnelitter, FPL/NextEra Energy	The technical Requirements specified are needed to be able to record data to the resolution necessary to allow accurate analysis. Refer to NPCC Document SP-6 Section VIII.B Digital Fault Recorder Performance.
R6.1	Is this intended to mean that the minimum duration of each fault record is one (1) second? Proposed Revision: "Records faults for a minimum duration of one (1) second." Dan Rochester, IESO	Wording changed for clarification. Wording made consistent with A-15 Section 4.6.

Comments Received--PRC-002-NPCC-01

Requirement No.	**Comment**	**Response**
R6.2	The technical requirements for fault duration as well as, the requirement to have a minimum recording rate of 16 samples per cycle will not allow the use of existing solid state relays that currently have fault recording capability. The increased costs associated with having to upgrade existing equipment to meet a more stringent recording requirement (one that may not necessarily provide a distinct benefit over the existing equipment) are significant, and the upgrade itself may not be necessary. Mike Sonnelitter, FPL/NextEra Energy	The technical Requirements specified are needed to be able to record data to the resolution necessary to allow accurate analysis. Refer to NPCC Document SP-6 Section VIII.B Digital Fault Recorder Performance.
R6.3.4	This looks like a separate requirement. Also, text does not fit the structure of the preceding paragraphs. Consider making this requirement R7 and renumbering requirements. Measures will also have to be modified if accepted. Proposed Revision: R7. Each Transmission Owner and Generator Owner shall document and report to the Regional Reliability Organization (RRO) Additional functions and deviation from the settings in R6.3.2 and R6.3.3. Dan Rochester, IESO	Changes were made to the wording. The Drafting Team decided to include it under R6.3, and made it R6.3.4. This was R6.4 in the original posting.

Comments Received--PRC-002-NPCC-01

Requirement No.	**Comment**	**Response**
Original R7	Looks like a typo. Proposed Revision: Replace "a faulty" with "fault". No timeframe is given for reporting to the RC and RRO. Dan Rochester, IESO	The Drafting Team reviewed R7 and felt that because faulty recorders should be replaced as part of maintenance, and that the addition of recorders should be in compliance with this document, the original Requirement R7 was deleted. Refer to the new R14.6 for both comments.
Original R7	Notification – Via C-22? – Replacing faulty equipment in-kind should not require notification to RC and RE. Rick White, Northeast Utilities	The Drafting Team reviewed R7 and felt that because faulty recorders should be replaced as part of maintenance, and that the addition of recorders should be in compliance with this document, the original Requirement R7 was deleted. Refer to the new R14.6.
R7.1	This comment is in reference to the old Requirement R8.1 (now R7.1): What happens if the peak load is say 33,000 MW? Should the RC pro rate the number of DDRs specified? R8.1(now 7.1) should probably say so explicitly. Dan Rochester, IESO	Wording changed.
R7.1	This comment in reference to the old Requirement R8.1 This can be confusing as not all areas in NPCC are 30,000 MW peak load. Why not use "one DDR per 3,000 MW of peak load", to ensure that the Maritimes Area has at least 1 DDR for its 5500 MW of peak demand (and should actually have two DDRs). Moreover, to meet the objectives of R8.2, it would seem that far more than the "minimum per MW of Load" will suffice. Robert Creighton, Nova Scotia Power Incorporated	Wording changed.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
Original R8.2	This comment is in reference to the old Requirement R8.2 (now R7.2): These are conditions to be considered by the RC in determining where DDRs should be located. Treating each sub-topic as a requirement may lead to subjective arguments with auditors. Rick White, Northeast Utilities	The wording is similar to what is Criteria A-15.
R7.2	"Major" is very subjective and should be defined unless "…establish its area's requirements for…" in the first line of R8 also includes within its scope this definition. Even if it does, the requirement should make it clear by saying so explicitly. Dan Rochester, IESO	Wording from A-15 Section 5.2 used to replace the original wording.
R8	Continuous recorders are required if they're installed after 1/1/09. Rick White, Northeast Utilities	The Drafting Team felt that it was appropriate to add this Requirement, but this Requirement be reworded to apply after to DDRs installed after this Standard is approved.
R9	These comments refer to the posted R8.3. There should be a maximum amount of pre-trigger data recorded for each event. There is also a typo. Proposed revision: When triggered, records triggered data for a minimum of sixty (60) seconds that includes a maximum pre-trigger period of XX seconds. Change "record" to "records" Dan Rochester, IESO	The posted Requirement R8.3 has been moved to R9. Regarding triggering, DDRs installed this document is approved are to be continuous recorders (refer to R8). Pre-trigger capability is inherent in earlier generations of this equipment.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R9	It is my understanding that the RC has no jurisdiction over the planning horizon - only the Operations Planning Horizon. Consider revising the scope to include Transmission Planner. Robert Creighton, Nova Scotia Power Incorporated	The Violation Risk Factors and "Horizons" are under review. The Reliability Coordinator is the appropriate responsible entity for this Requirement.
R9.3	This is too specific. R9 allows RC to set triggers. Robert Creighton, Nova Scotia Power Incorporated	Triggers listed are the minimum requirements, other additional triggers can be incorporated. The Reliability Coordinator shall develop trigger settings because of its consideration of the overall system.
R9.4	These triggers were selected based on the capabilities of various manufacturers' equipment. Not all manufacturers can support all triggers. They should be required only if available on the equipment. Rick White, Northeast Utilities	The triggers listed are the minimum requirement, and other triggers can be incorporated. The wording of R9 has been changed to reflect the concerns about the capabilities of the equipment.
R9.4	The triggers should also include voltage related phenomena. Vlad Stanisic, Ontario Power Generation	The triggers listed are the minimum requirement, and other triggers can be incorporated.
R10	DDR Robert Creighton, Nova Scotia Power Incorporated	Dynamic recorders changed to DDRs.
R10.3	DDR convert V and I values into positive sequence MW, MVar, Voltage and frequency. Does this Requirement obstruct the features of the DDR? Robert Creighton, Nova Scotia Power Incorporated	The features of a DDR are not diminished by this requirement.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R10.3	What is the intent of this requirement? It is not clear and so we are unable to comment meaningfully. Dan Rochester, IESO	The intent of this requirement is to define what elements should be monitored. The wording has been changed from the original posting.
R11	What's the point of reporting? How is the reporting done? Why report "additional" settings? Rick White, Northeast Utilities	Because R11 deals with additional settings and deviations, the Regional Entity should have the option to request it. The Regional Entity may need to know what these additional settings and deviations are to determine if they might be useful for system event analysis. The reporting of these additions and deviations would be done via letter.
Original R12	For the original Requirement R12: Where did this requirement come from? If this becomes a requirement, a process change will be required to address the need. Rick White, Northeast Utilities	The original Requirement R12 is addressed in R7. The original Requirement R12 was deleted.
Original R12	While R12 requires the RC to document its assessment of the need for DDRs at new major BPS installations, it does not indicate the criteria against which this evaluation should be carried out. If this is to be left to the discretion of the RC then these criteria should also be documented and submitted to the RRO, TOs and GOs. Alternatively, the standard should make this clear. Dan Rochester, IESO	This Requirement was deleted. Its content is addressed in R7.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R12	This refers to R13 in the original posting. It is not clear what entity pays for installation of DDRs and who eventually owns them? Vlad Stanisic, Ontario Power Generation	That information is outside the scope of this Standard.
Original R14	This refers to R14 in the original posting. It is not clear what entity pays for installation of DDRs and who eventually owns them? Vlad Stanisic, Ontario Power Generation	That information is outside the scope of this Standard.
R14	The maintenance and testing requirements should allow the TO/GO to take advantage of surveillance performed by the RC and possibly maintenance services performed by the RC. Testing of circuits should be linked to other testing performed on the circuits affected (e.g., relay maintenance). Rick White, Northeast Utilities	With the revisions to the Requirements, this is the old Requirement R15. The TO/GO are ultimately responsible for the maintenance and testing programs.
Original R14, R15	The data retention period for these two Requirements should be changed from 12 months to 3 years to make them consistent with the data retention period for all other Requirements. Greg Mason, Dynegy	Data retention was not referred to in the original R14 or R15. Will be addressed in Section D. Compliance.
R14	This was Requirement R15 in the original posting. We recommend that the guidance offered in B-26 be translated into a stand-alone white paper to be used in conjunction with this standard. Dan Rochester, IESO	Whatever pertinent NPCC B (Guides), and C (Procedures) document language is left over after the Standard is completed will be evaluated on a case by case basis to determination disposition.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
R15	This Requirement was R16 in the original posting. There seems to be no reason to separate NERC, the RRO and the RC since the measures and VSLs make no distinction. Dan Rochester, IESO	Requirement reworded.
R15	This Requirement was R16 in the original posting. How does a Transmission Owner or Generation Owner or Transmission Planner get access to recordings from the RC. The RC should be required to make disturbance data available for analysis. The RC is not the only entity that has a use for this data. Robert Creighton, Nova Scotia Power Incorporated	Requirement R15 has been revised to reflect this concern.
R16	This should refer to the latest version of a specific standard (IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files). Rick White, Northeast Utilities	This was the old Requirement R17. The Drafting Team agreed with the comment, and the new R16 was revised accordingly.
M3	Since R3 should not be a requirement, this should not be a Measure. Rick White, Northeast Utilities	Definition of Current zero time moved to the Definitions of Terms Used in Standard page. R3 remains a requirement.
M5	Reword – Not “recorded for the fault”, but “records for faults” Rick White, Northeast Utilities	Measure M5 revised.
M10	Wording needs to be improved. Rick White, Northeast Utilities	Measure M10 revised.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
M10	The uncertainty regarding R10 needs to be cleared up after which this measure can be reviewed. Dan Rochester, IESO	Wording in R10 has been changed.
M17	Add "evidence" to Measure M18 Jeffrey May	The original Measure M18 is now Measure M17. "Evidence" has been incorporated.
M17	There is a typo here. Proposed revision: Each Transmission Owner and Generator Owner shall have, and provide upon request, evidence that it maintained, recorded and provided to NPCC. Dan Rochester, IESO	The original Measure M18 is after revision Measure M17. Wording has been changed.
D.1.3	Add "calendar" to sentences 2, 3, and 4. Jeffrey May	The sentences have been reworded. Section D. Compliance is under review at the time of this issuance.
D.1.3	TO & GO retention for M13 is not correct. M13 is for the RC. Rick White, Northeast Utilities	The original M13 (R13) is M12 (R12) referring to the Reliability Coordinator.
D.1.3	There is a typo here (last sentence Section D 1.3). Proposed Change: Change "record" to "records". Dan Rochester, IESO	Change made.
D.2.R3	Proposed Revision: Insert "for" between "provide" and "up" in each column. Dan Rochester, IESO	VSL correct as written.

Comments Received--PRC-002-NPCC-01

Requirement No.	Comment	Response
D.2.R4	In all the VSLs for R4, replace "Transmission" with "Generation". Jeffrey May	"Transmission" replaced by "Generation".
D.2.R7	This referred to the original Requirement R8. It is unclear what this product represents. It seems the total set of sites should simply be the sum of the locations meeting subrequirements R8.2.1 to R8.2.7 (now R7.2.1 through R7.2.7).	The Drafting Team removed the wording you questioned. Section D Compliance is under review.
D.2.R10	The uncertainty regarding R10 needs to be cleared up after which this measure can be reviewed. Dan Rochester, IESO	Wording in R10 has been changed.
D.2.R11	Editorial change to each column. Also insert a comma after R10. Proposed change: The Reliability Coordinator failed to document and report to the NPCC TFSP, additional … Dan Rochester, IESO	The Drafting Team felt no changes were necessary.
D.2.R12	Editorial changes to each column. Proposed revision: Insert "Coordinator" after "Reliability"; change "it" to "its"; change "installing" to "install"; and change "DDR" to "DDRs". Dan Rochester, IESO	Changes made.

NPCC Second Posting Comments

Commenter: Kenneth Brown Comment Form Question	Commenter Response	DMSDT Response
1. Are the entities listed in A.4 Applicability correct for this Standard? If not, please provide suggestions.	Yes	---

2. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	No. 1. R1.2.2 -It is assumed that for a generator or GSU protection relay that trips a lockout relay, only the lockout relay needs to be wired to the SOE, and not the individual protection relay, correct? This clarification is important because the majority of old electromechanical protection relays do not have additional output contacts to wire to the SOE . 2. R.1.2.2 - Also, the intent of R1.2.2 needs to be better defined for which GO relay schemes are intended to be wired to the SOE. For example, we do not expect the intent for the GO is to connect alarms for all 4 kV relays at the gen stations to the SOE correct? Only Generator and GSU lockout relays, correct? Also, the last part of the sentence "…that have control of equipment identified in theis standard" is not clear. 2. The intent of R1.2.3 needs to be better defined. Is this referring to only carrier equipment communications, or Fiber optic as well? In addition it should only be teleprotection for protection schemes connected to the HV swithyard. If the gen station has any fiber optic on lower voltage equipment, it should not be applicable.	1, 2. The operation of a Protection Group needs to be monitored. The design of the Protection Group dictates what equipment conveys the Protection Group status to the SOE (this could be via a lockout relay, auxiliary relay, or measuring relay). 2. The standard has been reworded to address the concern regarding "that have control of equipment identified in this standard". 3. "Teleprotection" is defined in the NPCC Glossary A-7 as "A form of protection that uses a communication channel." Communication channels can use a variety of mediums. Teleprotection keying and receiving is independent of the communication medium. The teleprotection keying and receiving which affects the status of BES equipment or other equipment as defined in R1.1.

3.A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	No. R4 says the GO shall provide provide fault recording capability "… if fault recording capability for that portion of the system is inadequate". This needs some clarification. Specifically: 1. What does "…for that portion of the system…" mean? 2. By what criteria shall it be determined if it is "…inadequate…" or not? 3. Who makes that determination? Also, R4 refers to this requirement on at and above 200MVA. This should be a single generator nameplate 200MVA and above, not if unit has multiple modules that sum to 200MVA and above, correct?	1. Wording of the standard changed to eliminate the "portion of the system" concern. 2, 3. Requirement R4 only applies to generators connected to BES elements. Presently within the NPCC area BES elements are determined via A-10, Classification of Power System Elements testing methodology. By definition slow clearing faults on these elements may have a wide-area impact. Generating units was changed to "Generating Plants" to address the 200MVA multiple unit concern.
3.B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	No. The quantities in R5 are fine. However, regarding R6: 1. It should not be required that relays trigger the DFR. Otherwise the DFR will be triggered many times when there was no disturbance to monitor. Not all relay operations mean there is going to be a disturbance. 2. Undervoltage AND neutral overcurrent should not BOTH be required. The applicable entity should be allowed to pick one.	1. Comment accepted. The standard has been revised to allow for additional triggering in lieu of protective relay tripping. 2. The Drafting Team does not agree with the comment because the DFR should be triggered for all fault types. Having both undervoltage and neutral overcurrent triggering ensures that all faults will be detected. Additionally, the standard has been revised to include phase overcurrent as a triggering option to capture abnormal non-fault conditions such as overloads and power swings.
4.A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes. As long as the TO and GO still have the ability to review and comment on it as the RC develops it.	The Drafting Team understands and supports the comment.

4.B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	Yes. 1. As long as the TO and GO still have the ability to review and comment on it as the RC develops it. 2. I believe there is a wording mistake: "….shall develop DDR at least one of the following DDR trigger settings…."	1. The DT agrees with the comment. 2. Comment acknowledged, the requirement has been reworded.
5. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	No. R14.3 Automated alarms if the communication link is lost should eliminate the need for monthly verifications.R14.6 The grammar mistake "…service 90 within 90 days…" needs to be corrected.	Drafting Team revised the wording in R14.3 to reflect your comment. Editorial revision madeto R14.6.
6. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	I do not understand the question.	---
7. Do you agree this Standard satisfies the requirements of NERC PRC-002-1? If not, provide specific suggestions, and any other comments on the document.	Yes	---

Commenter: Michael Lombardi Comment Form Question	Commenter Response	DMSDT Response
1. Are the entities listed in A.4 Applicability correct for this Standard? If not, please provide suggestions.	Yes	---
2. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	No. We believe it should say "Be provided at all BES substations…"	Comment noted, the "Purpose" revised to explain that all equipment or facility references will be to Bulk Electric System.

3.A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	Yes. NU agrees with the elements listed in R2 -- as long as Protection Group trip outputs are accessible as DDR inputs from Distribution protection system that trip BES elements. PSNH practice is to monitor the required values in the "transmission" DFR. There is also SOE data from relays where numerical relays have been applied. If Protection Group trip outputs are not accessible as DDR inputs from Distribution protection system that trip BES elements, then the elements of R2 should be expanded to capture Distribution protection system that trip BES elements. The basis for NU's comments is -- In NH, the relaying in our 115/34.5 kV substations typically has one or more relay that are transformer related protection that trip transmission assets. In a number of instances, there is separate distribution and transmission control houses and data would have to be collected from the distribution control house. Also, some of those distribution relays may be numerical relay and be able to provide SOE and oscilography for faults. These would be another source of fault data.	Information from the distribution system can be useful in post event analysis, but monitoring distribution equipment is outside the scope of this standard. Entities can monitor equipment beyond what's prescribed in the requirement.
3.B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	Yes	---

4.A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	---
4.B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	No. R9 needs to be reworded. Consider the following: "Each Reliability Coordinator shall develop at least one of the following DDR trigger settings (based on manufacturers' equipment capabilities) that, when triggered will record triggered data for a minimum of sixty (60) seconds." R10.1 is unclear to us.	After review by the Drafting Team, requirement R9 has been reworded. The intent of R10.1 is to ensure that during maintenance activities there will still be adequate DDR coverage in a station.
5. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	Yes. R14.6 has an extra "90" in the text.	Correction made.
6. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	Yes. Experience has shown that post event analysis is extremely time consuming and often lacks the detailed information needed to draw meaningful conclusions regarding the performance of system elements. The lack of detailed information stems from entities "doing their own thing" as it relates to the deployment, configuration, and reporting of equipment used in the monitoring of system disturbances. Setting a standard for disturbance recording sets the scene for improved event analysis which can be expected to lead to improved system modeling and protection scheme performance. These will drive reliability improvements.	The Drafting Team acknowledges the positive comment.

7. Do you agree this Standard satisfies the requirements of NERC PRC-002-1? If not, provide specific suggestions, and any other comments on the document.	No. It's not apparent that this document includes requirements for the sample rate for DDRs. Updated Comments provided in NU's 7/14/09 submittal We are concerned that the definition of 'capacity' is not clear. It is defined in the draft subject document as, "Capacity: The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment." For a generator the capacity is not the nameplate gross minus the station service. It is the claimed capability of the unit which is usually less than nameplate but can be higher in some cases. We would prefer words such as "normal maximum net rated output or present rated maximum net output. PRC-002 should also be consistent with the NPCC definition in A-7: NPCC A-7 Capacity — The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment. Baseload Capacity — Capacity used to serve an essentially constant level of customer demand. Baseload generating units typically operate whenever they are available. Firm Capacity — Capacity that is as firm as the seller's native load unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting reserve is carried by the seller. Intermediate Capacity — Capacity intended to operate fewer hours per year than baseload capacity but more than peaking capacity. Typically, such generating units have a capacity factor of 20% to 60%. Net Capacity — The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs. The only thing missing with the above "Net Capacity" definition is the clarity that it is the current capacity (which could be higher or lower than nameplate because of modifications and operating limitations). This concern is also an issue with regard to the draft requirements in R1 and R4 that are shifting from MW to MVA and the apparent assumption that it is nominal nameplate MVA. This should also be clarified consistent with the above comments	Capacity as used in the standard is as defined in A-7. The Drafting Team used nameplate Capacity to have a fixed parameter to define which generating units or plants would be required to meet the Disturbance Monitoring Equipment requirements.

Commenter: Mike Garton Comment Form Question	Commenter Response	DMSDT Response
1. Are the entities listed in A.4 Applicability correct for this Standard? If not, please provide suggestions.	Yes	---
2. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	No. The MVA ratings requiring DME installation in the NPCC Region seem overly restrictive given those being proposed in NERC draft Standard PRC-002-2 . Additionally, the standard should not require both the TO and GO to install DME, provided there is a process in place, such as agreements, to collect the required data for analysis. Requirement R1.1 states "Be provided at all substations…" What is the voltage level. Does this mean every substation regardless of voltage level or 100kV and above?	The unit/plant capacity thresholds were generated from extensive event analysis experience, and are consistent with those specified in the NPCC approved criteria A-15, Disturbance Monitoring Equipment Criteria. It is the DME SDTs continued belief that the 50/300MVA threshold provides adequate data for quality wide-area event analysis (fulfilling the purpose of the standard) without requiring all units to have full SOE capabilities. The purpose of event analysis is not only to determine the root cause, but also how the system responded during the event. Generation is one of the most important system elements, and knowing their status changes during the BES event would greatly help the analysis and understanding of the system disturbance. Certainly, losing any 50 MVA generator would not cause any more than local reliability concerns. However, losing a cluster of 50 MVA generators due to a local disturbance could spread the local event to a wide-area system disturbance. The intent of the standard is to provide adequate SOE monitoring, and not have redundant information. This can be achieved through agreements between T.O.'s and G.O.'s. A statement has been added to the "Purpose" to address that all equipment and facilities are BES.

3.A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	---	---
3.B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	Yes. I agree with the electrical quantities specified and recording capabilities; however, suggest changing Requirement R5.5 to read "Real and reactive power."	Comment accepted. Standard revised to read "Real" power.
4.A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	---
4.B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	No. NERC draft Standard PRC-002-2 Requirements R 7 and R8 provide more specific information on what is to be recorded. Suggest revising to be consistent with the NERC requirements.	The NERC standard is in draft status. After the PRC-002 is approved, the requirements you mention will be reviewed and the NPCC standard revised accordingly if necessary. Frequency and real and reactive power has been added to R10.
5. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	No. Maintenance and testing is included in NERC Standard PRC-018-1, Requirement R6. The requirements contained in Requirement R14 are more prescriptive than PRC-018-1; therefore suggest alignment with the outcome of NERC Project 2007-11.	The requirements in the standard do align with PRC-018 R6, and by design are more prescriptive. After NERC Project 2007-11 is completed and approved, the NPCC standard will be reviewed with respect to the contents of the NERC document.

6. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	No. Post disturbance analysis is not addressed within the NPCC standard or draft NERC Standard PRC-002-2; therefore, it is not possible to draw any conclusions with respect to future reliability improvements of the system..	The Drafting Team feels that the standard ensures that adequate Disturbance Monitoring Equipment is installed throughout NPCC to provide sufficient data to facilitate event analysis.

Commenter: Paul DiFilippo

Comment Form Question	Commenter Response	DMSDT Response
1. Are the entities listed in A.4 Applicability correct for this Standard? If not, please provide suggestions.	---	---
2. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	---	---
3.A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	---	---
3.B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	---	---
4.A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	---	---
4.B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	---	---
5. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	---	---

6. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	---	---
7. Do you agree this Standard satisfies the requirements of NERC PRC-002-1? If not, provide specific suggestions, and any other comments on the document.	No. In regards to Requirement R6.3 it is not necessary to trigger DFRs from protection operation if you use: 1. Phase U/V triggering (0.85 pu or better) 2. Neutral O/C triggering (0.2 pu or lower) 3. Phase O/C triggering (1.5 pu or lower) The combination of these triggers should capture all faults on the power system and provide back-up coverage for neighboring stations. It should not necessarily be a requirement to trigger on protection operation.	---

7. Do you agree this Standard satisfies the requirements of NERC PRC-002-1? If not, provide specific suggestions, and any other comments on the document.	No. Additional comments not previously provided: 1. This standard should not require both the TO and GO to install DME, provided there is a process in place, such as agreements, to collect the required data for analysis. Requiring both TO and GO to install DME is redundant and does not increase the reliability of the Bulk Electric System. 2. Requirement R15.3 (page 6) is blank. 3. The role of the Reliability Coordinator (RC) is not clear in Requirements R15, R16, and R17. These requirements should only be applicable to those entities (i.e., TO and GO) that actually collect and analyze the data. (Do not believe that the RC does this). 4. NERC Standard PRC-002-2 is currently in the open process for comment (Project 2007-11). This standard combines the requirements of PRC-002-1 and PRC-018-1. Suggest NPCC suspend development of a regional standard until the requirements of the national standard are finalized and regulatory approved. For members with assets in multiple regions, Regional Standards based on NERC Standards provide more consistency. 5. VSL's are impacted by previous comments on Requirements and /or Measures.	1. The intent of the standard is to provide adequate DME monitoring, and not have redundant information. This can be achieved through agreements between T.O.'s and G.O.'s. 2. R15.3 was a typograhical error that has been corrected. 3. The Drafting Team does not agree with the comment. There are areas within NPCC where the Reliability Coordinator is responsible for collecting data and performing event analysis. 4. Because of the lag in development of the NERC standard, NPCC felt that there was a responsibility to have a regional standard in place. Afer a NERC standard is finalized, the NPCC regional standard will be reviewed. 5. The Drafting Team agrees. As indicated in the Comment Form's cover sheet the final VSLs were under review at the time of the posting.

Commenter: Thomas C. Duffy

Comment Form Question	Commenter Response	DMSDT Response
1. Are the entities listed in A.4 Applicability correct for this Standard? If not, please provide suggestions.	---	---
2. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	---	---
3.A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	---	---
3.B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	---	---
4.A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	---	---
4.B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	---	---
5. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	---	---
6. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	---	---

7. Do you agree this Standard satisfies the requirements of NERC PRC-002-1? If not, provide specific suggestions, and any other comments on the document.	No. It appears that the requirements of this Regional Standard go beyond the requirements of the NERC PRC-002-1 Standard, specifically in regards to Fault recording capability. The Standards Drafting Team has elected to replace the term BPS with BES, which makes the future application of this Regional Standard problematic. NERC's Standard PRC-002-1 charges the regions with the establishment of requirements for installation of Disturbance Monitoring Equipment (DME) and reporting of Disturbance data. Specifically, no reference is made in the NERC Standard to the BES. More pointedly, it empowers the individual regions to specify the 'location (e.g., by voltage, geographic area, station size, etc.)' where DME is required. It does not stipulate that specific DME must be applied to all facilities classified as BES facilities, rather, it dictates that adequate and sufficient DME should be prescribed, by the individual regions, to facilitate analysis of events and to verify system models. Further, the NPCC RSAR for PRC-002-NPCC-1 described the stated intent of this Regional Standard as supportive of bulk power system reliability. NPCC has maintained that it's performance based methodology for determining BPS facilities is a superior methodology for evaluating transmission facilities that are vital to the operation of the electrical system within the NPCC footprint. Applying DME, specifically Fault monitoring equipment standard requirements, to hundreds of non-BPS transmission facilities is draconian since the non-BPS transmission elements have been proven to be essentially immaterial to the reliable operation of the BPS in the Northeast US and Eastern Canada region. The RSC should re-consider the utilization of the BES definition as a means to dictate where transmission facility Fault recording capability will be required in this NPCC Regional Standard. To this end, the RSC should carefully inspect the intent of, and the latitude provided by, the NERC standard (PRC-002-1) in regards to the determination of an adequate level of DME to determine whether the requirements prescribed by the utilization of the BES definition within this Regional Standard are necessary and appropriate.	Refer to Guy's May 27, 2009 E-mail.

Commenter: Vladimir Stanisic Comment Form Question	 Commenter Response	 DMSDT Response
1. Are the entities listed in A.4 Applicability correct for this Standard? If not, please provide suggestions.	Yes/No. As expected, the second draft of this regional standard is an improvement compared to the first one. OPG agrees that the standard should be applicable to GOs. OPG remains concerned, however, with the direction the standard continues to take, especially with respect to the applicability and the requirements related to generating facilities. This draft introduces the notion that “Bulk Electric System”, which is currently not a defined NPCC term, and “Bulk Power System” are interchangeable. This reemphasizes inconsistency with other related NPCC reliability documents which are based on the concept of Bulk Power System as defined in A10. This automatically creates the risk of ambiguous interpretations. Further, this draft of the standard still uses the MVA capacity of generating units as a threshold to determine applicability of disturbance monitoring requirements for Generating facilities. This ignores the fact that in many cases generating units are not part of the BPS, regardless of their capacity and hence have no impact on its reliability. As stated in the OPG’s submission on the first draft of this standard, while we acknowledge the ongoing discussions with FERC regarding the content and structure of A10, the drafting team should not assume changes to the A10 document by enshrining principles in other documents (like this one) that are inconsistent with existing NPCC approved documents. It should be noted that any FERC direction with respect to A10 modifications will need to be discussed within NPCC and those discussions will certainly contemplate FERC's jurisdictional authority.	Unless otherwise identified, the equipment and facilities listed in the standard are understood to be part of the BES. At this point in time NPCC's BES and BPS remain one in the same. There are activities underway which may change that relationship, with BES becoming 100kV and above and BPS being the NPCC A-10 derived system. The standard is being written to apply to a NPCC A-10 derived system as it exists today. A FERC ruling stating that all standards in NPCC shall apply to 100kV and up will represent a change in applicability and "balloon" the applicability. Until such time as this BPS-BES issue is decided the term BES will be used in the standard; it is consistent with NERC and is the same as our BPS A-10 system today.

2. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	No. Several entities, including OPG, questioned the low generator MVA capacity that sets a threshold for the applicability of R1 and suggested different applicability criteria. While the drafting team refuted the comments, implying that the suggestions were arbitrary, the team did not make an effort to substantiate their own proposals. On that note, most of large generators likely have some form of SOE and DFR already. Nevertheless, it should be understood that by current NPCC criteria, strongly supported by OPG, only those facilities identified as the elements of BPS do have material impact on the reliability of the regional interconnected power system. Hence, PRC 002-NPCC-1 should be applicable only to BPS facilities as indicated in the preamble of the NPCC's request for comments:All references to the equipment and facilities in the Standard unless otherwise noted are to the Bulk Power System as defined in … A 10 …For all other facilities implementation of disturbance monitoring should be dealt with on a local level if and when necessary and should not be elevated to the level of a regional standard. Given a significant monetary and logistics impact of the requirements, OPG urges the drafting team to do a survey of actual disturbance analyses performed following major Bulk Power System events in the NPCC region. This should help to determine realistically the nature of the disturbance data required to successfully carry out such a task.	The unit/plant capacity thresholds were generated from extensive event analysis experience, and are consistent with those specified in the NPCC approved criteria A-15, Disturbance Monitoring Equipment Criteria. It is the DME SDTs continued belief that the 50/300MVA threshold provides adequate data for quality wide-area event analysis (fulfilling the purpose of the standard) without requiring all units to have full SOE capabilities. The purpose of event analysis is not only to determine the root cause, but also how the system responded during the event. Generation is one of the most important system elements, and knowing their status changes during the BES event would greatly help the analysis and understanding of the system disturbance. Certainly, losing any 50 MVA generator would not cause any more than local reliability concerns. However, losing a cluster of 50 MVA generators due to a local disturbance could spread the local event to a wide-area system disturbance. The intent of the standard is to provide adequate SOE monitoring, and not have redundant information. This can be achieved through agreements between T.O.'s and G.O.'s. A statement has been added to the "Purpose" to address that all equipment and facilities are BES.

3.A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	No. The following qualifier from R4 leaves much to interpretation:"…if Fault recording capability for that portion of the system is inadequate." • Who determines and based on what criteria whether the fault recording capability in the portion of system is adequate • Why is it inadequate? Did other entities in that portion of the system failed to fulfill their obligations with respect to providing fault recording capability? In relation to this requirement, OPG states again that providing DFR capability for generating units and plants is of little practical value, especially taking into account that transmission owners are required to provide it as per R2.	R4 has been reworded to address your concerns. Requirement R4 only applies to generators connected to BES elements. Presently within the NPCC area BES elements are determined via A-10, Classification of Power System Elements testing methodology. By definition slow clearing faults on these elements may have a wide-area impact.
3.B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	In line with the previous comment, OPG does not consider DFR information taken at generating stations to be critical for BPS analysis.It would help if the drafting team could provide an actual example of a BPS event where DFR data supplied by generators proved to be indispensable for the post-event analysis.	This comment is not directly related to the question. Concerns have been addressed in the DT's response to question 3A.
4.A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	---
4.B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	Yes/No. In general the trigger settings seem reasonable. The exceptions is R9.3 that specifies 20 mHz delta frequency.A typical generator governor dead-band is 36 mHz so there is no point recording anything below that value.	The standard stipulates that there are other triggers that can be used. However, the 20mHz Delta Frequency trigger is a recommendation based on system operations experience.

5. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	No. R14.3, R14.4, R14.5 seem redundant. All those activities are actually an integral part of a maintenance and testing program. Their periodicity should be determined accordingly and not prescribed in the standard.	Maintenance and testing programs might not include the items specified in R14.3, R14.4, and R14.5. Performing those activities is integral to the successful use of Disturbance Monitoring Equipment, and as such are stipulated in the standard.
6. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	No. DDRs as proposed would not be sufficient to assess transient and mid-term dynamic performance of generator controls of individual units. This was an important element of Aug 2003 Blackout investigation, particularly with regards to the performance of large generating units.	The Drafting Team discussed that after analysis of the 2003 Blackout there was a lack of mid-term (15-20 seconds into the event) data at the individual unit level. The purpose of DDRs are to capture a larger overview of the system response, not necessarily individual generators.
7. Do you agree this Standard satisfies the requirements of NERC PRC-002-1? If not, provide specific suggestions, and any other comments on the document.	Yes/No. In general this standard does meet most of the requirements of PRC-002-1. Nevertheless, verification of system models stated in the purpose of PRC 002-1 is not addressed, as OPG pointed out in the previous comment period. More importantly, OPG is unclear as to why NPCC proceeds with the development of a regional standard based on the NERC standard that is slated to be retired in a near future. The standard PRC 002-2 that will replace PRC 002-1 is in advanced stage of development. Moreover, the applicability and the requirements of PRC 002-2 are considerably different from the current draft of PRC -002-NPCC-1.	Inferring that the standard is requiring monitoring to verify system modelling is outside the scope of this standard. The Drafting Team noted that draft standard PRC-002-2 removed that language. Standard PRC-002-NPCC-1 is being developed because it is not known when the NERC standard will be approved.

NPCC Third Posting Comments

Commenter: Dan Rochester Comment Form Question	Commenter Response	DMSDT Response
1. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	Yes	----
2A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	Yes	----
2B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	Yes	----
3A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	----
3B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	Yes	----

Commenter: Dan Rochester Comment Form Question	Commenter Response	DMSDT Response
4. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	Yes/No Monthly verification of communications seems excessive where DME has local storage. This should be specified by the TO and GO. If a disturbance occurs and it is discovered that the data on a DME cannot be accessed remotely because the communication link is broken, it would then be up to the responsible entity to manually retrieve the data before it is over-written.	The DMSDT believes that the communication channels are integral to secure the data capability of the DME in a timely manner. It is consistent with A-15 and B-26. In addition, NERC PRC-018 requires a ten day data storage period.
5. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	Yes	----
6. If you have any additional comments on this Standard that you have not submitted above, please provide them here.	R9 should include minimum data storage capability. We suggest restating 9.1 and 9.2 as follows: 9.1 A minimum recording time of sixty (60) seconds per trigger event 9.2 A minimum data sample rate of 960 samples per second and a minimum data sample rate for RMS quantities of six (6) data points per second. M3 - Insert "Bulk Electric System" before "transmission elements" for consistency with R3	The storage capability of DME is specified in R1.2 of NERC PRC-018-1. The suggested revisions to R9.1, and R9.2 were incorporated. In R9.2, "data sample rate" was changed to "data storage rate" for RMS quantities. Added the wording to M3.

Commenter: Dan Rochester Comment Form Question	Commenter Response	DMSDT Response
7. Do you agree with the Implementation Plan? If no, please provide your comments and suggestions.	The implementation plan addresses only the installation of the DDRs. It does not address the RC's role in determining their requirements and locations, which is a pre-requisite to the GOs and TOs achieving the implementation plan.	The DMSDT feels the intent of the Implementation Plan is addressed in the document.

Commenter: David Bertagnolli Comment Form Question	Commenter Response	DMSDT Response
1. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	Yes	----
2A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	Yes	----
2B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	Yes	----
3A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	----
3B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	No Two suggestions: R9.3.1 Rate of change of frequency…recommend 20 mHz/second.	R9.3.1--the RC sets the triggers. R9.3.3--This is a recommendation based on previous experience and study. It is ultimately the RC's responsibility to set a trigger based on what it

Commenter: David Bertagnolli Comment Form Question	Commenter Response	DMSDT Response
	R9.3.3 Delta Frequency (recommend 20 mHz change)…the recommendation should be 80 mHz change because scheduled frequency on the Eastern Interconnection is frequently set to 20 mHz low or high for time error corrections, so a 20 mHz change would result in triggering for normal frequency excursions.	requires.
4. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	Yes	----
5. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	Yes	----
6. If you have any additional comments on this Standard that you have not submitted above, please provide them here.	Typos: R1.1…..substationsand… R14.6…to service 90 within 90 days…	Revisions made.
7. Do you agree with the Implementation Plan? If no, please provide your comments and suggestions.	No The implementation plan should not go into effect until such time as the standard is approved by FERC or other regulatory authorities as appropriate.	The Implementation Plan will go into effect after FERC/Canadian Provincial approvals. The Implementation Plan will be revised.

Commenter: Kenneth Brown Comment Form Question	Commenter Response	DMSDT Response
1. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	No As others have perviously commented, the threshold for SOE requirements is low at 50MVA for a single generator @ 50MVA or plant at 300MVA. What is the basis for a single unit and plant of this size to have SOE? This puts undue requirements on smaller older units as compared to other regions. Can the smaller units w/o SOE be grandfathered? A single larger unit higher threshold (in concert with R4 of 200MVA) seems more appropriate.	Smaller units without Sequence of Events recording equipment will not be grandfathered. It is important for post event analysis that all impactive generation provide the data required. The DMSDT, as it has expressed at earlier meetings, believes that the the size of the generators specified is necessary to ensure having the availability of adequate information for post event analysis. The "smaller" unit size specification is deliberately made to account for the prolifieration of distributed generation, generally comprised of smaller units. The distributed electrical connections of these smaller machines magnifies the importance of their output contributions to the system.
2A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	No Is requirement R4 intended to be an plant aggregate of GSU ratings or a threshold of a single GSU rating?	This requirement does not refer to GSU ratings, but the generator/generators rating as per the defintion for Generating Plant.
2B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	No R5 refers to the required monitored elements but R2 does not specify scope of elements for GO, only for a TO. The GO elements required to be monitored or location (high side/Low side) required	R5 refers to quantities, not elements. R2 specifies the elements to be monitored by the TO. R4 specifies the requirements for the GO. High side or low side quantities may be adequate to satisfy the requirement.

Commenter: Kenneth Brown Comment Form Question	Commenter Response	DMSDT Response
	should be listed as well.	
3A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	----
3B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	Yes	----
4. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	No R14.4 monthly verification of time synchronization is too frequent for modern day monitoring equipment that is monitored; PSEG suggests a frequency of once per year. Note R14.6 "service 90 within 90 days" needs grammatical correction.	In R14.6 the typographical error has been corrected. R14.4 has been reworded to require monthly checks for unmonitored clocks.
5. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	Yes	----

Commenter: Kenneth Brown Comment Form Question	Commenter Response	DMSDT Response
6. If you have any additional comments on this Standard that you have not submitted above, please provide them here.	R11, R12 and R13 references requirements of DDR for GOs. There is not a GO threshold (MVA) for DDR requirements. This should only be a GO requirement for very large GOs. Where different GOs may be in a clustered region this is better placed in TO's responsibility for coordination. Measure M4 has requirements of units > 200MVA and requirement R4 has generating plants requirement of > 200MVA, R1.1 has requirements for units and plants. Use of plants and units does not seem consistent.	Response: R7 provides direction for the RC in determining the location of DDR installations. R12 and R13 are requirements for GOs if the RC determines that a DDR is required at their facility. R11 is not a requirement for GOs, however R14 is. M4 has been revised to say Generating Plants.
7. Do you agree with the Implementation Plan? If no, please provide your comments and suggestions.	No comment.	----

Commenter: Michael R. Lombardi Comment Form Question	Commenter Response	DMSDT Response
1. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	Yes	----
2A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	Yes	----
2B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	Yes	----
3A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	----
3B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	Yes	----

Commenter: Michael R. Lombardi Comment Form Question	Commenter Response	DMSDT Response
4. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.		
5. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	Yes	----
6. If you have any additional comments on this Standard that you have not submitted above, please provide them here.	There are two typos/grammar mistakes that should be resolved: Section A.R.1.1. First sentence, Add a space between "substationsand" Section A.R14.6. First sentence, the first instance of "90" should be removed.	Revisions made.
7. Do you agree with the Implementation Plan? If no, please provide your comments and suggestions.	Yes	----

Commenter: Mike Garton Comment Form Question	Commenter Response	DMSDT Response
1. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	Yes	----
2A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	Yes	----
2B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	Yes	----
3A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	----
3B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	Yes	----

Commenter: Mike Garton Comment Form Question	Commenter Response	DMSDT Response
4. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	Yes The first sentence in Requirement R14.6 reads, "A requirement to return failed units to service 90 within 90 days." Remove the first "90" in the sentence.	Revised.
5. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	No In responding to this same question during the last comment period, we noted: "Post disturbance analysis is not addressed within the NPCC standard or draft NERC Standard PRC-002-2; therefore, it is not possible to draw any conclusions with respect to future reliability improvements of the system." The Drafting Team's response was "The Drafting Team feels that the standard ensures that adequate Disturbance Monitoring Equipment is installed throughout NPCC to provide sufficient data to facilitate event analysis." Perhaps I do not understand the question, but the Standard simply does not require post disturbance analysis. The Standard's purpose is to "Ensure that adequate disturbance data is available to facilitate Bulk Electric System event analysis." Given that, I believe the standard will meet the stated purpose.	This question could have been worded better to reflect the Standard's intended purpose.
6. If you have any additional comments on this Standard that you have not submitted above, please provide them here.	1. We commend the NPCC Drafting Team for drafting a regional standard to meet the requirement of the current NERC Standard, PRC-002-1, which requires each Regional Reliability Organization to develop, coordinates, and	As part of the ERO's Rules of Procedure Section 300 related to standards development, the ERO has the authority to "direct" the regions to develop regional standards. The ERO had sent the Regions a letter in 2006 directing the development

Commenter: Mike Garton Comment Form Question	Commenter Response	DMSDT Response
	document a UFLS program (fill-in-the-blank standard). In FERC Order No. 693, the Commission expressed concern regarding the potential for the fill-in-the-blank standards to undermine uniformity. The Commission further notes, "the ERO should consider whether greater consistency can be achieved in this Reliability Standard." We recognize that NERC is developing a continent-wide reliability standard per Project 2007-11 PRC-002-2 , Disturbance Monitoring and Reporting Requirements. The development of a regional reliability standard seems premature at this point and it would better serve the industry to wait until the continent-wide standard is fully vetted via the open process. 2. The third draft NPCC Regional Reliability Standard PRC-002-NPCC-1, Disturbance Monitoring, was posted on the NPCC website on September 9, 2009 for comments through October 24, 2009. Subsequently, on October 1, 2009, the second draft of the NPCC regional standard was posted on the NERC website for industry review through November 16, 2009. The concurrent (i.e., NPCC and ERO) posting of a third draft regional reliability standard is not specifically allowed by the NPCC Regional Reliability Standards Development Procedure (RRSDP). In fact, Step 6 (Solicit Public Comment on Draft Standards) specifically states “Final draft standards will be concurrently posted on the ERO website for comments.” One could argue that a regional reliability standard still in the	of four regional standards to augment the development of their respective continent wide standard, which you are in receipt of in my 10/14.09 email to you. Although NERC’s standard is in the developmental stages, the requirement to develop a regional standard still exists for NPCC. In addition, the existing proposed standard was developed using existing criteria already in place in A-15 criteria document so the vast majority of the northeast should already be adhering to the standard. NPCC has met with FERC and NERC staff and all continue to agree, that although laudible to have one set of requirements throughout the continent in a single ERO standard, the slow progress of the NERC ERO drafting team to achieve broad consensus will likely result in a “lower bar” reliability standard that won’t meet the needs of the northeast without more specificity and a stringent set of regional requirements. Therefore the NPCC regional standard will accomplish two goals, one to expeditiously put into place a set of requirements for the NPCC region, and second, create a set of requirements based on the more stringent needs of the regional experts engaged in disturbance analysis. This is a blackout related standard and as such to take a “wait and see” attitude for what happens with the continent wide standard is unacceptable to FERC and does not reflect on the performance of NPCC as a region to develop and maintain robust system reliability. It is in NPCC's best interest to have this standard in place. The development of the NERC standard,

Commenter: Mike Garton Comment Form Question	Commenter Response	DMSDT Response
	NPCC open process comment phase until October 24, 2009, is not a final draft standard and posting on NERC's website is premature and violates fair due process.	whose completion date not clear, will trigger a review of our NPCC regional standard and appropriate revisions will be made to remove redundant requirements. The requirements making the NPCC document more stringent will be left in place and should the continent wide standard encompass all the NPCC requirements, the regional standard will be retired. Having no standard in place currently is not acceptable at this time to regulators. Also to note is that RFC already has a Disturbance Monitoring Standard in place. -- NERC is soliciting administrative or process comments with their posting of PRC-002-NPCC-01. Step 6 of the NPCC Regional Reliability Standards Development Procedure does stipulate that "Final draft standards will be concurrently posted on the ERO website for comments". It does not preclude NERC posting earlier versions. Also, NERC is charged with ensuring that standards and their development must be transparent, justifying whatever postings NERC feels are necessary.
7. Do you agree with the Implementation Plan? If no, please provide your comments and suggestions.	No The Implementation Plan for PRC-002-NPCC-1 should be based on FERC approval rather than NERC Board of Trustees, since this timetable presupposes a FERC approval or a FERC approval on a set schedule. FERC could reject or request modifications and then as proposed by NPCC, generators would be have to make another round	The Drafting Team agrees, and the wording in the Implementation Plan will be changed accordingly to reflect FERC and Canadian entity approval to ensure uniformity in its application.

Commenter: Mike Garton Comment Form Question	Commenter Response	DMSDT Response
	of adjustments to reconcile to FERC.	

Commenter: Patricia Lynch Comment Form Question	Commenter Response	DMSDT Response
1. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	Yes	----
2A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	No In the previous version of this draft regional standard dated 7/15/09, R4 was applicable for DFR installations on any unit above 200 MVA whereas this version has shifted to include all plants at 200 MVA or above. What is the justification for placing many more facilities with smaller units that have less impact to the BPS into scope?	An aggregate of capacity 200MVA and greater connected to a single GSU is equivalent to what would be a single larger unit with a capacity of 200MVA or greater. Not every generator has to be monitored, but the "common" GSU. The impact is considered from the BES perspective via the GSU, not the individual units.
2B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	Yes	----
3A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	----
3B. Do you agree with the DDR trigger settings	Yes	----

Commenter: Patricia Lynch Comment Form Question	Commenter Response	DMSDT Response
specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.		
4. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	Yes/No Monthly verification of communications seems excessive where DME has local storage. This should be specified by the TO and GO. If a disturbance occurs and it is discovered that the data on a DME cannot be accessed remotely because the communication link is broken, it would then be up to the responsible entity to manually retrieve the data before it is over-written.	The DMSDT believes that the communication channels are integral to secure the data capability of the DME in a timely manner. It is consistent with A-15 and B-26. In addition, NERC PRC-018 requires a ten day data storage period.
5. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	Yes	----
6. If you have any additional comments on this Standard that you have not submitted above, please provide them here.	Although the definition for generating plant is explained in the definition of terms, it does not necessarily imply the conventional use of the term. For example, if a generating facility has several units with total capacity equal to 300 MVA but interconnected at several points where the loss of a group of units would not necessarily result in a loss of full facility capacity, DMEs would not be in scope. This term should be clarified or changed to prevent confusion.	For the purposes of the standard, the term Generating Plant is correctly interpreted in your example. Any group of units where a single event will result in the loss of defined capacity of generation qualifies under the definition, and is subject to the provisions of the standard.

Commenter: Patricia Lynch Comment Form Question	Commenter Response	DMSDT Response
7. Do you agree with the Implementation Plan? If no, please provide your comments and suggestions.	Yes	----

<u>Commenter</u>: Saurabh Saksena <u>Comment Form Question</u>	<u>Commenter Response</u>	<u>DMSDT Response</u>
1. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	Yes	----
2A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	Yes R3 is not a specification for where fault recording is required to be installed.	R3 is in fact a specification for the TO to determine where fault recording capability is to be installed. The TO is responsible for installing dfr capability in such a manner that it will capture complete fault information for any BES transmission element as per R2.
2B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	Yes Recommend removing the phrase "if used" from R5.3 - polarizing quantities. Most relays operate on a polarizing quantity that can be determined from the monitored elements. R6.3 With the exception of "Protective Relay tripping for all Protection Groups", none of the other requirements is a function and therefore the requirement is unenforcable.	There are certain times when polarizing quantities might not be required. Therefore, it is not necessary to directly monitor those quantities. --- The DT agrees with your comment, and has revised the wording in R6.3, and R6.4.
3A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	----

Commenter: Saurabh Saksena Comment Form Question	Commenter Response	DMSDT Response
3B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	Yes Text Suggestion: Change "DDR requirements" in R10.1 and R10.2 with "DDR functionality". Maintenance cannot interfere with DDR requiments - interfere with correct DDR functionality, perhaps - but not requirements.	R10.1 and R10.2 revised to reflect the comment.
4. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	No Do not agree with the check of calibration settings on a two year interval. This implies that disturbance monitoring equipment is more critical than protective relays. A calibration check should be done on the same time interval as bulk electric system protection. Suggest that as part of the monthly communication and synchronization check that it be observed that all analog channels are recording. Also, only the failure to establish a program is discussed. What if a program is in place but a single fault recorder wasn't called every month? Finally,the difference between High and Severe VSLs is very confusing. One of the two options in the Severity VSL is the same as High VSL.	Calibration settings of DME software is different from the calibration of protective relays (scaling, triggering, and other unique factors that are not applicable to protective relays). Users interface more frequently with DME than with protective relays, so there is more of an opportunity to change settings inadvertently. A monthly testing periodicity is unnecessarily excessive. Analog testing is performed during the required maintenance and testing program. If a single recorder wasn't called every month, that is a failure of the testing program. This is no different than omitting a device from any other testing program. There is a difference between the VSLs.
5. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	No The standard does not really address post disturbance analysis. The standard does address the criteria for installation of DME to ensure disturbance data is available for post disturbance	The Drafting Team agrees with your assessment. The standard does not address post disturbance analysis directly, but the resources that can provide the data to do the post disturbance analysis. Good analysis can only lead to good reliability.

Commenter: Saurabh Saksena Comment Form Question	Commenter Response	DMSDT Response
	analysis. SOE, and fault and dynamic disturbance records captured by DME provided important data that aids post disturbance analysis. The use of that data in a post disturbance analysis is what can lead to improvements in system reliablity.	
6. If you have any additional comments on this Standard that you have not submitted above, please provide them here.	Compliance - 1.3 Data Retention - "… shall keep evidence for twelve calendar months for Measure 14…" Measure 14 "...evidence that it has a maintenance and testing program…" The data retention requires record keeping for only 1 year of a program that repeats every 2 years. It's a good practice to keep evidence of a maintenance program on an ongoing basis by retaining records at least until the next maintenance activity. Otherwise there really isn't evidence of a program.	Drafting Team to give to Ben Li.
7. Do you agree with the Implementation Plan? If no, please provide your comments and suggestions.	Yes	----

Commenter: Vlad Stanisic Comment Form Question	Commenter Response	DMSDT Response
1. Do you agree with the locations required in R1 to have Sequence of Events recording capabilities, and the elements to be monitored? If not, please explain why and provide suggestions.	No During past comment periods many entities, including OPG, questioned low generator MVA capacity that sets a threshold for the applicability of R1 and suggested different applicability criteria. Regrettably, the same concerns have to be restated again. The arguments for extensively implementing SOEs at generating facilities do not seem justified. From OPG's experience the only time SOE records from generating stations were required and were of practical use was during the investigation of the Blackout of 2003. Even then, only major units that tripped ahead of others were analyzed in detail by the TOP. On that note, most of large generators likely have some form of SOE and DFR already. Nevertheless, it should be understood that by current NPCC criteria, strongly supported by OPG, only those facilities identified as the elements of BPS do have material impact on the reliability of the regional interconnected power system. Hence, PRC 002-NPCC-1 should be applicable only to the BPS facilities. For all other facilities, implementation of disturbance monitoring should be dealt with	The DMSDT, as it has expressed at earlier meetings, believes that the size of the generators specified is necessary to ensure having the availability of adequate information for post event analysis. The "smaller" unit size specification is deliberately made to account for the proliferation of distributed generation, generally comprised of smaller units. The distributed electrical connections of these smaller machines magnifies the importance of their output contributions to the system. NPCC's BES and BPS remain one in the same. There are activities underway which may change that relationship, with BES becoming 100kV and above and BPS being the NPCC A-10 derived system. The standard is being written to apply to a NPCC A-10 derived system as it exists today. A FERC ruling stating that all standards in NPCC shall apply to 100kV and up will represent a change in applicability and "balloon" the applicability. Until such time as this BPS-BES issue is decided the term BES will be used in the standard; it is consistent with NERC and is the same as our BPS A-10 system today.

Commenter: Vlad Stanisic Comment Form Question	Commenter Response	DMSDT Response
	locally (within an area), if and when necessary, and should not be elevated to the level of a regional standard.	
2A. Referring to requirements R2 through R4 for Fault recorders, do you agree with the Elements that are required to have Fault recording capability provided for? If not, please explain why and provide suggestions.	No Requirement R4 seems illogical. It appears to cater for cases when TO fails to fulfill the requirements of R2 with respect to providing fault recording capability? In relation to this requirement, OPG states again that providing DFR capability for generating units and plants has largely theoretical value.	R4 is logical in the sense that it requires the GO/TO to provide the required quantities for event analysis. It is necessary that the GO and TO work together and mutually cooperate to fulfill the requirements of R4. The contributions of generators to BES events is real, and must be monitored to facilitate post-event analysis. In the experience of the Drafting Team, the fault contribution information froma generating plant is essential for proper post-fault analysis.
2B. Do you agree with the electrical quantities specified in R5, and the Fault recording capabilities specified in R6? If not, please explain why and provide suggestions.	No In line with the previous comment, OPG does not consider DFR information taken at generating stations to be critical for BPS analysis. It would help if the drafting team could ilustrate a need for DFR records by providing an actual example of a BPS event where DFR data supplied by generators proved to be indispensable for the post-event analysis. Regarding R5, why would DFRs record	In the experience of the Drafting Team, the fault contribution information from a generating plant is essential for proper post-fault analysis. R5 does not require the recording of frequency, real and reactive power, just provide the quantities to be able to determine them.

Commenter: Vlad Stanisic Comment Form Question	Commenter Response	DMSDT Response
	frequency and real and reactive power? Those quantities are aleady covered by DDRs?	
3A. Referring to requirement R7 for Dynamic Disturbance Recording (DDR), do you agree with each RC establishing its area's requirements as specified in R7? If not, please explain why and provide suggestions.	Yes	----
3B. Do you agree with the DDR trigger settings specified in R9, and the Elements to be monitored in R10? If not, please explain why and provide suggestions.	Yes/No In general the trigger settings seem reasonable. The exceptions is R9.3.3 that specifies 20 mHz delta frequency. Typical generator governor dead-band is 36 mHz so there is no point recording anything below that value. It would be essentially just noise.	The 20mHz setting is appropriate, and it is explained in the paper accessed at http://trucorg.accountsupport.com/files/2006/FDA_2006_010.pdf. The 20mHz change refers to a system frequency change, not an individual generator frequency response.
4. Do you agree with the maintenance and testing program requirement in R14? If not, please explain why and provide suggestions.	No The requirements for maintenance and testing seem excessive. For example, why monthly verification of communication channels? Why requesting basis for maintenance and testing intervals?	DME is independent of protection equipment. When using IEDs, the intent is to have exsisting maintenance programs used. R14 is directed at stand alone equipment, and was revised to reflect this. Calibration settings of DME software is different from the calibration of protective relays (scaling, triggering, and other

Commenter: Vlad Stanisic Comment Form Question	Commenter Response	DMSDT Response
	OPG recommends including this subject into the latest revision of NERC PRC – 005 and alinging it with the requirements related to protections maintenance rather than having it in PRC- 002- NPCC. All those activities may be viewed as an integral part of protections maintenance and testing program. Their periodicity should be determined accordingly and not prescribed in the standard.	unique factors that are not applicable to protective relays). Users interface more frequently with DME than with protective relays, so there is more of an opportunity to change settings inadvertently. A monthly testing periodicity is not unnecessarily excessive. It is important to be able to know with reasonable assurance that DME can be interrogated when needed. Analog testing is performed during the required maintenance and testing program. If a single recorder wasn't called every month, that is a failure of the testing program. This is no different than omitting a device from any other testing program. There is a difference between the VSLs.
5. Although the Standard addresses post disturbance analysis, do you believe that this Standard provided information that can lead to improvements in reliability of the system in the future? If not, please explain why.	Yes/No This will depend on whether DDRs would be sufficient to assess transient and mid-term dynamic performance of generator controls. This was an important element of Aug 2003 Blackout investigation, particularly with regards to the performance of large generating units.	The purpose of DDRs are to capture a larger overview of the system response, not necessarily individual generators. It is agreed that from a generator's performance this has value, but the question is directed from a system reliability perspective.
6. If you have any additional comments on this Standard that you have not submitted above, please provide them here.	OPG remains concerned with the direction the standard continues to take, especially with respect to the applicability and the requirements related to generating facilities. This draft reinforces the notion that “Bulk Electric System”, which is currently not a	Unless otherwise identified, the equipment and facilities listed in the standard are understood to be part of the BES. At this point in time NPCC's BES and BPS remain one in the same. There are activities underway which may change that relationship, with BES becoming 100kV and above and BPS being the NPCC A-10 derived system. The standard is being written to apply to a NPCC A-10 derived system as it exists today. A FERC ruling

Commenter: Vlad Stanisic Comment Form Question	Commenter Response	DMSDT Response
	defined NPCC term, and “Bulk Power System” are interchangeable. This reemphasizes inconsistency with other related NPCC reliability documents which are based on the concept of Bulk Power System as defined in A10. In OPG's view, this is a fundamental error. In addition, given a significant monetary and logistics impact of the requirements, OPG urges the drafting team to do a survey of actual disturbance analyses performed following major Bulk Power System events in the NPCC region. This should help determining the acutal nature of the disturbance data required to realistically carry out such analyses.	stating that all standards in NPCC shall apply to 100kV and up will represent a change in applicability and "balloon" the applicability. Until such time as this BPS-BES issue is decided the term BES will be used in the standard; it is consistent with NERC and is the same as our BPS A-10 system today. In the experience of the Drafting Team, the fault contribution information from a generating plant is essential for proper post-fault analysis.
7. Do you agree with the Implementation Plan? If no, please provide your comments and suggestions.	This standard should await adoption of NERC's PRC - 002 standard. There is currently no urgency to complete a regional standard on the same subject. Current practices seem to be sufficient.	Because of the value DME adds to system reliability, it is in NPCC's best interest to have a standard in place. The development of the NERC standard is in its infancy, completion date not clear. The NPCC standard is also being developed at NERC's urging. RFC already has a Disturbance Monitoring Standard in place.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

January 7, 2010

Subject: <u>Notification of Ballot Results for Regional Standard PRC-002-NPCC-01 Disturbance Monitoring</u>

Dear Madam/Sir:

The ballot period for NPCC Regional Standard PRC-002-NPCC-01 and its Implementation Plan closed last night Jan. 6, 2010, with the Standard being approved by ballot. All eight NPCC Sectors participated. Results were as follows:

<u>Quorum</u>: 100% of Sectors participated
<u>Approval</u>: 84%

A recommendation for final Regional approval will be sent to the NPCC Board for their consideration. After Board approval, the Standard will be sent to the NERC/ERO Board of Trustees for approval.

PRC-002-NPCC-01 and its Implementation Plan are posted on the NPCC Website, and can be viewed at:

<u>NPCC :: Regional Standards :: Under Development :: PRC-002-NPCC-01</u>

The documents may be viewed and / or downloaded by clicking “Doc” under the “Document” column, the “Pre-Ballot Review” row.

I want to thank everyone for taking the time to participate in this ballot, and if you need any additional information, please contact me.

Thank you.

Lee Pedowicz
Manager, Reliability Standards
Northeast Power Coordinating Council, Inc.
212.840.1070 (p)
212.302.2782 (f)
lpedowicz@NPCC.org

PRC-002-NPCC-01: Disturbance Monitoring

Quorum Results

Sector	Total Regist	Total Attend	% Attend	Passed Quorum
Sector 1, Transmission Owners	18	15	0.83	Yes
Sector 2, Reliability Coordinators	5	4	0.80	Yes
Sector 3, TDUs, Dist. And LSE	14	7	0.50	Yes
Sector 4, Generator Owners	20	11	0.55	Yes
Sector 5, Marketers, Brokers, Aggregators	15	9	0.60	Yes
Sector 6, Customers - Large and Small	3	2	0.67	Yes
Sector 7, State and Provincial Reg. and Govt Authorities	6	4	0.67	Yes
Sector 8, Sub Regional Rel Councils, REs and Others	5	3	0.60	Yes
Total				8

Quorum has: **Passed**

Sector Results

Sector	Total Approve	Fraction	Total Disapprove	Fraction	Total Abstain	Sectors Voted
Sector 1, Transmission Owners	13	0.87	2	0.13	0	Yes
Sector 2, Reliability Coordinators	3	0.75	1	0.25	0	Yes
Sector 3, TDUs, Dist. And LSE	7	1.00	0	0.00	0	Yes
Sector 4, Generator Owners	4	0.40	6	0.60	1	Yes
Sector 5, Marketers, Brokers, Aggregators	5	0.71	2	0.29	2	Yes
Sector 6, Customers - Large and Small	1	1.00	0	0.00	1	Yes
Sector 7, State and Provincial Reg. and Govt Authorities	2	1.00	0	0.00	2	Yes
Sector 8, Sub Regional Rel Councils, REs and Others	2	1.00	0	0.00	1	Yes
Totals	37	6.73	11	1.27	7	8

Ballot has: **Passed**

PRC-002-NPCC-01: Disturbance Monitoring

Sector	Organization	Representative
Sector 1, Transmission Owners	Central Hudson Gas and Electric Corporation	Thomas Duffy
Comment: CHG&E respectfully submits a 'Disapprove' vote for this standard. We concur with the comments presented by several of the other Entities that, until it can be established that the technical requirements of the standard would apply solely to A-10 BPS elements in the NPCC region (as was intended by the standard's drafting team), the approval of this standard and it's associated implementation plan is premature.		
Sector 1, Transmission Owners	FPL	William C. Locke, Jr.
Comment: technical drafting problems need to be corrected		
Sector 1, Transmission Owners	Northeast Utilities	David Boguslawski
Comment: Revision will be required if NPCC goes to the "100 KV and above brightline" to avoid applicability to generators less than 50 MVA, due to the NPCC NERC registrations taking place for generators over 20 MVA.		
Sector 2, Reliability Coordinators	ISO-New England, Inc.	Don Gates
Comment: ISO New England is supportive of technical content of the subject Regional Standard. ISO New England however, is submitting a NO vote with the hope and expectation that the concerns identified below can be easily resolved. First, there are two Requirements, namely R.16 & R.17 that assign obligations on the Reliability Coordinator inappropriately. These draft Requirements appear to "require" three different parties – the Generator Owner, Transmission Owner and Reliability Coordinator, to submit, maintain and/or record data for the same equipment. The draft Requirements establishes obligations for the Transmission Owners and Generator Owners specifically. Considering the role that Reliability Coordinators play, we see no need to create a redundant requirement for Reliability Coordinators to also maintain and/or record data for the equipment that the Transmission Owners and Generator Owners in their areas already maintain and/or record. If the purpose of the approach in the draft was to make sure to apply the Requirements to Reliability Coordinators that do own assets and who are not registered Transmission/Generator Owners, than the draft should make clear that Reliability Coordinators who do not own assets are exempt from the Requirements. On the other hand, if the intent of the draft was to create a redundant responsibility for the Reliability Coordinators than we do not support this approach. Second, we believe the Measures, specifically, M.8, M.10, M.11, do not comport with the Requirements as set forth in the Standard. In short, while the Requirements impose the key obligations on the Transmission/Generator Owners, these Measurements are directed at the Reliability Coordinator. This disconnect does not benefit reliability and can create confusion among Registered Entities about which registered entity is		

actually responsible for the compliance obligations in the Requirement. Moreover, as written, the Measures may impose additional responsibility on the ISO with respect to installation, monitoring and documenting deviations – again for equipment not owned by the ISO. Of course, if the necessary changes are made, we would be in a position to fully support the Standard.		
Sector 3, TDUs, Dist. And LSE	Northeast Utilities	Douglas McCracken
Comment: Revision will be required if NPCC goes to the "100 KV and above brightline" to avoid applicability to generators less than 50 MVA, due to the NPCC NERC registrations taking place for generators over 20 MVA.		
Sector 4, Generator Owners	Dominion Resources Inc.	Mike Garton
Comment: FERC approved NERC Reliability Standard PRC-018-1, Disturbance Monitoring Equipment Installation and Data Reporting, Requirement 1 states in part, "Each Transmission Owner and Generator Owner required to install DMEs by its Regional Reliability Organization (reliability standard PRC-002 Requirements 1-3) shall have DMEs installed that meet the following requirements…" Additionally, Requirement 2 of PRC-018-1 states, "The Transmission Owner and Generator Owner shall each install DMEs in Accordance with its Regional Reliability Organizations" installation requirements (reliability standard PRC-002 Requirements 1 through 3). NERC Reliability Standard PRC-002-1, Define Regional Disturbance Monitoring and Reporting Requirements, is not FERC approved; however PRC-018-1 clearly expects the Regional Reliability Organization's requirements to be based on Requirements 1-3 of NERC PRC-002. Since NERC PRC-002 is not FERC approved, development and approval of the NPCC Regional Standard, in our view, presents a compliance issue with PRC-018-1. Dominion recognizes that NERC is developing a continent-wide reliability standard per Project 2007-11 – PRC-002-2, Disturbance Monitoring and Reporting Requirements. The development of a regional reliability standard on DMEs seems premature at this point. Stakeholders (who must purchase, install and operate DME requirement at their sites) would have a lower probability of regional conflicts or inconsistencies on this item if regional standards were completed after the continent-wide standard is fully vetted.		
Sector 4, Generator Owners	NextEra Energy Resources	Christopher Orzel
Comment: The standard drafting team has confused the terms Bulk Electric System (NERC) and Bulk Power System (A-10) elements. As a result this standard will apply to all NERC registered entities regardless of A-10 status. Based on direct input from the drafting team on a December 16 conference call that NPCC hosted, this is not what the standard drafting team intended. NextEra does not disagree with the technical merits of this standard, however as the standard is currently written there is a significant discrepancy between what we believe the "spirit" of the standard is and what the requirements state. Ultimately, it will be the requirements, not the "spirit" to which a NERC registered entity will be measured for compliance. Our primary area of concern is surrounding the standard drafting team's use of the term "Bulk Electric System" in the standard's "Purpose" section and in multiple requirements (R3 & R4). - In a NERC standard (Regional or National), the term "Bulk Electric System" refers to all NERC registered assets. - In NPCC, NERC registered assets are NOT THE SAME AS A-10 Bulk Power System elements. During the December 16, 2009 call NPCC held regarding this standard, the standard drafting team said that the standard was intended to only apply to Bulk Power		

System (A-10) connected elements, and if it was going to apply to all NERC registered assets that the standard would have to be re-written. Again, here the “spirit” (A-10) and requirement (all NERC registered assets) do not line up. Until this issue can be resolved and the “spirit” of the standard is clearly documented in the requirement of the standard, NextEra can not vote in favor of this standard.		
Sector 4, Generator Owners	NRG Energy Inc.	Patricia Lynch
Comment: It is apparent that the drafting team needs to clarify the standards applicability as it stands today as it is definitely not clear. In addition, the threshold for applicability to generators that have minimum impact to the BES should be elevated to the levels that are consistent with other regions or explain the justification for this requirement as it is presently written.		
Sector 4, Generator Owners	Ontario Power Generation Inc.	Colin Anderson
Comment: OPG cannot support this draft for the following reasons: 1. Questionable applicability of the standard - there is ambiguity regarding "BPS" "BES" and "A-10" applicability. 2. Use of MVA thresholds for generating units is inappropriate and is in contradiction to the current NERC draft of PRC-002-02 3. Ambiguous requirements and VSLs - (i.e. R4 and R13 which have both been raised previously) 4. Implementation plan does not seem to be consistent with NERC timelines as per PRC-002-02		
Sector 4, Generator Owners	Power City Patners	Lisa Cona
Comment: The drafting team wrote this standard based upon NPCC’s definition of the Bulk Power System (units that are connected to an A10 Bus). This creates an internal inconsistency within NPCC since NPCC is currently registering units based upon the NERC BES definition of 100 KV or greater. The NPCC registry now includes small generators that tie to a 100 KV bus but may not be connecting to an A10 bus. This standard creates a situation that burdens small generators to comply with a standard in which the requirements were written for units connected to the A10 buses. If the standard was rewritten based upon the definition of BES, I would assume the requirements for small generators would be applied only to larger units. Another inconsistency exists across regions with this standard with respect to small generator requirements, specifically to RFC’s PRC-002 standard that requires SOE recorders at generating units greater than 250 MVA or aggregate plant capability of greater than 750 MVA that tie to the BES at 200 KV and greater. Uniform applicability must be used for the industry to move toward a consistency across regions. For this reason Power City Partners, LLC is not in agreement with this standard and must vote against it.		
Sector 5, Marketers, Brokers, Aggregators	Constellation Energy Commodities Group, Inc.	Glen McCartney
Comment: Given the proposed PRC-002-NPCC standard language, Constellation Energy must vote negative until certain conflicts and clarifications are resolved. Constellation Energy would like clarification on NPCC’s use of the terms “Bulk Electric System” and “Bulk Power System.” The proposed standard language uses the term “Bulk Electric System;” however, the discussion on the pre-ballot conference call implied use of the term “Bulk Power System.” As the definitions under NERC are different, consistent and intentioned use of the terms is critical to enabling compliance. Please clarify the language to unambiguously identify to which entities the standard applies – all NERC registered entities in NPCC or those elements connected to the Bulk Power System (A-10). In addition, we would like		

further explanation on how refueling outages will be considered when determining compliance. Thank you for your attention to these concerns.		
Sector 5, Marketers, Brokers, Aggregators	PPL EnergyPlus, LLC	Mark A. Heimbach
Comment: PPL EnergyPlus, who also represents PPL Generation in the NPCC voting process, is voting no because of the following reasons: The discrepancy between the NERC registry criterion and the NPCC-A10 "element criterion" is a significant one that should be resolved before this is standard is approved. Also, the standard needs to clearly delineating the responsibilities of the TO and the GO in order to minimize overlaps between the two. The TO should have the core responsibility for this equipment as the equipment exists to analyze events on the Bulk Electric System, the common point for all entities, and the domain of the TO. The equipment should be owned and managed by a regulated entity, like the TO, that can spread the costs of this equitably between all participants. Similarly when it is time to update the equipment, the TO can manage that effort more easily than involving all of the Generator Owners. GO's should have clearly delineated responsibilities to deliver their appropriate quantities to the TO for recording on the TO's equipment.		
Sector 5, Marketers, Brokers, Aggregators	Utility Services LLC	Brian Evans-Mongeon
Comment: Currently, absent FERC stating otherwise, standards within NPCC are applied based upon the A-10 methodology. Today, A-10, BPS, and BES all reference the same facilities. This standard was developed based upon the A-10 facilities and thus is treated as the Bulk Electric System. NPCC also needs an implementation plan to phase in the applicability of this standard as it cannot be applied upon a successful passing vote of NPCC. Should the BES be defined by the FERC during this post voting period, then applicability of the standard and or the implementation period will have to be modified. However, as it stands today, there is no FERC authority to extend the applicability beyond the BPS. Further, looking at the NPCC Board action to not ask for the applicability of the BES assessment to be imposed, we view this as further support for the application of this standard to be on the A-10 facilities. Due to these reasons, Utility Services votes to approve the regional standard proposal.		

Regional Reliability Standard
<u>Submittal Review Checklist</u>

Region: Northeast Power Coordinating Council (NPCC)
Regional Standard Number: PRC-002-NPCC-1
Regional Standard Title: Disturbance Monitoring
Date Standard Received: 05/14/10
Date Region Notified of Receipt: 05/25/10
Date NERC Evaluation Completed: 07/03/10
Submittal Review Status:

☒ Complete

☐ Incomplete

Reviewed by:
Stephanie Monzon, Manager of Regional Standards
Gerry Adamski, Vice President and Director of Standards
Approved by:
Stephanie Monzon, Manager of Regional Standards

Review of Request for Completeness:

1. Was a concise statement of the basis and purpose (scope) of request supplied?

   ☒ Yes

   ☐ No

2. Was a concise statement of the justification of the request supplied?

   ☒ Yes

   ☐ No

3. Was the text of the regional reliability standard supplied in MS Word format?

   ☒ Yes

   ☐ No

4. Was an implementation plan supplied?

   ☒ Yes

   ☐ No

5. Was the regional entity standard drafting team roster supplied?

   ☒ Yes

   ☐ No

6. Were the names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard supplied?

   ☒ Yes

   ☐ No

7. Were the final ballot results, including a list of significant minority issues that were not resolved, supplied?

   ☒ Yes

   ☐ No

8. For each public comment period, was a copy of each comment submitted and its associated response along with the associated changes made to the standard supplied?

   ☒ Yes

   ☐ No

Review of Standard for Completeness:

Title

9. Is there a title that provides a brief, descriptive phrase identifying the topic of the standard?

☐ Yes

☒ No The standard's title is: "Disturbance Monitoring"

Number

10. Does the standard have a unique identification number not already used by any NERC reliability standard?

☒ Yes

☐ No

Purpose

11. Does the purpose explicitly state what reliability-related outcome will be achieved by the adoption of the standard?

☒ Yes: "Ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses"

☐ No

Applicability

12. Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted?

☒ Yes: Transmission Owners, Generator Owners, and Reliability Coordinators

☐ No

13. Does this reliability standard identify the geographic applicability of the standard, such as the entire interconnection, or within a regional entity area?

☐ Yes

☒ No: the standard purpose and applicability does not note that the standard applies only to entities within NPCC.

14. Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria?

☒ Yes: it is noted in the Purpose that "All references to equipment and facilities herein unless otherwise noted will be to Bulk Electric System (BES) elements."

☐ No

Effective Date

15. Does the effective date start on the 1st day of the 1st quarter after entities are expected to be compliant?

☐ Yes

☒ No

Effective Date: To be established.

16. Does the effective date provide time to file with applicable regulatory authorities and provide notice to responsible entities of the obligation to comply?

☒ Yes

☒ No

The standard's effective date does not establish implementation obligations; however, the proposed implementation plan does establish a phased approach for compliance.

Requirements

17. Does each requirement identify the functional entity that is responsible and the action to be performed or the outcome to be achieved?

☒ Yes

☐ No

18. Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

☒ Yes

☐ No

19. Are the requirements free of additional comments or statements for which compliance is not mandatory, such as background or explanatory information?

☒ Yes

☐ No

Violation Risk Factors

20. Is there a Violation Risk Factor (High, Medium, Lower) for each requirement?

☒ Yes

☐ No

Time Horizons

21. Is there a Mitigation Time Horizon (Long-term Planning; Operations Planning; Same-day Operations; Real-time Operations; Operations Assessment) for each requirement?

☒ Yes

☐ No

Measures

22. Does each measure identify to whom the measure applies and the expected level of performance or outcomes required to demonstrate compliance?

☒ Yes: The Measures identify the responsible entities established in the Requirements.

☒ No: The Measures do not provide examples of evidence but rather only refer back to the associated Requirement.

23. Is each measure tangible, practical, and as objective as is practical?

☐ Yes

☒ No: cannot determine based on the Measures as written.

24. Does each measure clearly refer to the requirement(s) to which it applies?

☒ Yes

☐

25. Is there a measure for each requirement?

☒ Yes

☐ No

Compliance Monitoring Responsibility

26. Is the 'Electric Reliability Organization' identified as the Compliance Monitor?

☐ Yes

☒ No Compliance Monitor – NPCC Compliance Committee

Compliance Monitoring Period

27. Does the standard identify the time period in which performance or outcomes is measured, evaluated, and then reset?

☐ Yes

☒ No (not applicable) – this section no longer applies and will be removed from the Standards template.

Data Retention

28. Does the standard identify the data retention requirements and assignment of responsibility for data archiving?

☒ Yes

☐ No

Additional Compliance Information – None Stated in the Proposed Standard

29. Does the standard identify the process that will be used to evaluate data or information for the purpose of assessing performance or outcomes?

☐ Yes

☒ No

30. Does the standard identify the specific data or information that is required to measure performance or outcomes?

☐ Yes

☒ No

31. Does the standard identify the entity that is responsible for providing data or information for measuring performance or outcomes?

☐ Yes

☒ No

Violation Severity Levels

32. Is there a Violation Severity Level (lower, moderate, high, severe) for violation of each of the requirements?

☒ Yes

☐ No

Associated Documents

33. If there are standards or forms that are referenced within a standard, are the full names and numbers of the standard identified under, 'Associated Documents'.

☐ Yes

☒ No

Definitions

34. Are the definitions used and provided in the standard consistent with the NERC definitions.

☒ Yes:

☐ No

Other Observations:

35. Are there any additional comments?

☒ Yes: NPCC is proposing two regional definitions (if approved applicable to the NPCC region)

☐ No

Current Zero Time: The time of the final current zero on the last phase to interrupt.

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

Exhibit D

NPCC Disturbance Monitoring Standard Drafting Team Roster with Background Information

Dave Bertagnolli

Education: B.S.E.E., M.S.

Licenses/Certifications: Professional Engineer (Connecticut), Senior Member IEEE

Employer at the time PRC-002-NPCC-01 was written: ISO-New England

Brief Description of Experience Relevant to PRC-002-NPCC-01: Lead the dynamic disturbance recording program in New England since 1989. Member and past president of the Transient Recorder Users Council which organizes the Fault and Disturbance Analysis Conference at Georgia Tech. Participant in the North American Synchro-Phasor Initiative (NASPI) and member of several NASPI Task Teams.

Larry Brusseau--Standards Manager
MID-Continent Area Power Pool

Paul DiFilippo

Education: BSc. Applied Science - Electrical Engineering

Licenses/Certifications: Association of Professional Engineers of Ontario

Employer at the time PRC-002-NPCC-01 was written: Hydro One Networks Inc.

Brief Description of Experience Relevant to PRC-002-NPCC-01: Field Protection, Protection and Control Technical Services analyzing transmission system protection operations, lead in the August, 2003 Blackout investigation. Experience as Protection and Control Reliability Standards Manager, member of the NPCC TFSP.

Gerry Dunbar

Education: B.A. Economics, Siemens Power Technology Course

Licenses/Certifications:

Employer at the time PRC-002-NPCC-01 was written: Northeast Power Coordinating Council

Brief Description of Experience Relevant to PRC-002-NPCC-01: Thirty years of power system operations experience which included assignments as a qualified bulk power substation operator, instructor substation operations, control room operator (transmission and distribution operations).

Frank Ettori--Process Owner, Planning, Engineering, Operations
Vermont Transco

Brian Evans-Mongeon

Education: Degree in Electrical/Electronic Technology, B.S.B.A.

Licenses/Certifications:

Employer at the time PRC-002-NPCC-01 was written: Utility Services, Inc.

Brief Description of Experience Relevant to PRC-002-NPCC-01: Collected input from clients regarding disturbance monitoring equipment for use by the Drafting Team. Evaluated how the Standard would affect clients.

John R. Ferraro

Education: B.S.E.E.

Licenses/Certifications: Professional Engineer (Connecticut, Maine)

Employer at the time PRC-002-NPCC-01 was written: Northeast Utilities

Brief Description of Experience Relevant to PRC-002-NPCC-01: Responsibilities as a Manager and Engineer in Transmission Protection and Controls Engineering included the design of relay applications and the analysis of relay performance (including post-event analysis of the 2003 blackout). Also worked on improvements at nuclear power plants, and fossil and hydro generation facilities. Senior Member of IEEE since 1996 Member of NPCC Task Force on System Protection from 2001-2010; Chairman from 1/2006 to 1/2008.

Jim Ingleson

Education: B.S, M. Eng.--Electric Power Engineering

Licenses/Certifications: Professional Engineer (New York, Massachusetts)

Employer at the time PRC-002-NPCC-01 was written: New York Independent System Operator

Brief Description of Experience Relevant to PRC-002-NPCC-01: Responsible for NYISO disturbance recorders and event analysis. Was the Chair of the Transient Recorder Users Council. Was Chair of the PSRC Working

Group I11 on “Timing Considerations for Event Reconstruction”. Contributed to IEEE Standard C37.232 “IEEE Recommended Practice for Naming Time Sequence Data Files”.

Donal Kidney--Manager, Compliance
NPCC

Quoc Le--Manager, System Planning and Protection
NPCC

Lee Pedowicz
Education: B.S.E.E., M.S.--Electric Power Engineering, G.E. Power Systems Engineering Course
Licenses/Certifications: Professional Engineer (New York), NERC Reliability Operator
Employer at the time PRC-002-NPCC-01 was written: Northeast Power Coordinating Council
Brief Description of Experience Relevant to PRC-002-NPCC-01: Bulk and Distribution Power System Operations which utilized Disturbance Monitoring equipment to analyze and respond to system disturbances, protective relay, control, supervision, and monitoring equipment field operations, testing, installations.

Robert J. Pellegrini
Education: B.S.E.E., PTI Graduate Certificate
Licenses/Certifications: Professional Engineer
Employer at the time PRC-002-NPCC-01 was written: United Illuminating
Brief Description of Experience Relevant to PRC-002-NPCC-01: As Manager Protection Control SCADA, designed and implemented several DFR's and SCADA systems.

Jeremiah Stevens
Education: B.S.E.E., M.S.E.E.
Licenses/Certifications: Professional Engineer (New York)
Employer at the time PRC-002-NPCC-01 was written: New York Independent System Operator
Brief Description of Experience Relevant to PRC-002-NPCC-01: Responsible for monitoring and maintaining NYISO's DDR recorders.

Xiaodong Sun
Education: B.Eng. of Electrical Engineering, M.Sc. of Control Engineering
Licenses/Certifications: Licensed P.Eng by Professional Engineers Ontario (PEO)
Employer at the time PRC-002-NPCC-01 was written: Ontario Power Generation Inc.
Brief Description of Experience Relevant to PRC-002-NPCC-01: 15 years working in Transmission and Generating Stations as a Protection and Control Engineer. Familiar with reliability standards and technical compliance requirements for generators. Extensive experience in design, commissioning, maintenance, and troubleshooting of protection systems and familiar with Protection and Control working procedures and Protection Design Standards. Hands-on experience in commissioning, maintenance, and troubleshooting of SCADA, RTU, DFR, SER, and PLC systems.

John Vasco--Section Manager, Relay Protection Engineering
Consolidated Edison Company of New York, Inc.

Guy Zito
Education: B.S.E.E., PTI
Licenses/Certifications:
Employer at the time PRC-002-NPCC-01 was written: Northeast Power Coordinating Council
Brief Description of Experience Relevant to PRC-002-NPCC-01: Planning and Operating experience of Transmission and Distribution systems, reviewed system disturbances and the data required to properly analyze and mitigate those occurrences.

Exhibit E

PRC-002-NPCC-01 Violation Severity Level and Violation Risk Factor Analysis

This document provides the justification for assignment of VRFs and VSLs, identifying how each proposed VRF and VSL meets NERC's criteria and FERC's Guidelines. NERC's criteria for setting VRFs and VSLs; FERC's five guidelines (G1 – G5) for approving VRFs; and FERC's four guidelines (G1-G4) for setting VSLs are provided at the end of this document.

PRC-002-NPCC-01 VRF and VSL Justifications--R1		
R1	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Not applicable
	Proposed Lower VSL	The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed Up to10% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
	Proposed Moderate VSL	The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed more than 10% and up to and including 20% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
	Proposed High VSL	The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed more than 20% and up to and including 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.
	Proposed Severe VSL	The Transmission Owner or Generator Owner provided the Sequence of Event recording capability meeting the bulk of R1 but missed more than 30% of the total set, which is the product of the total number of locations in 1.1 times the total number of parameters in 1.2.

	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs are consistent with PRC-018-1 Requirement R2 that establishes the same increments within the VSLs: **Lower**: The responsible entity is non-compliant in that no more than 10% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3. **Moderate:** The responsible entity is non-compliant in that more than 10% but less than or equal to 20% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3. **High:** The responsible entity is non-compliant in that more than 20% but less than or equal to 30% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3. **Severe:** The responsible entity is non-compliant in that more than 30% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is not binary and does not violate this guideline Guideline 2b: the VSL is gradated properly. The violation gradations d noot overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL assignment does not alter the associated requirement but rather is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R2		
R2	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed Requirement refers to the elements in Requirement R3. Both Requirements are assigned a Medium VRF.
	Proposed Lower VSL	The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed… Up to and including 10% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
	Proposed Moderate VSL	The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed… More than 10% and up to and including 20% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
	Proposed High VSL	The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed… More than 20% and up to and including 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.
	Proposed Severe VSL	The Transmission Owner provided the Fault recording capability meeting the bulk of R2 but missed… More than 30% of the total set, which is the total number of Elements at all locations required to be installed as per R3 that meet the criteria listed in 2.1 through 2.6.

	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs are consistent with PRC-018-1 Requirement R2 that establishes the same increments within the VSLs: **Lower**: The responsible entity is non-compliant in that no more than 10% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3. **Moderate**: The responsible entity is non-compliant in that more than 10% but less than or equal to 20% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3. **High**: The responsible entity is non-compliant in that more than 20% but less than or equal to 30% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3. **Severe**: The responsible entity is non-compliant in that more than 30% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is not binary and does not violate this guideline Guideline 2b: the VSL is gradated properly. The violation gradations should not overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R3		
R3	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	Not applicable.
	Proposed Moderate VSL	Not applicable.
	Proposed High VSL	Not applicable.
	Proposed Severe VSL	The Transmission Owner failed to provide… Fault recording capability that determines the current zero time for loss of transmission Elements.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The existing standards do not require that current zero time be determined.
	FERC VSL G2 Violation Severity Level	Guideline 2a VSL is binary and does not violate this guideline – the single level is severe.

	Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding Requirement .
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R4		
R4	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*

	Proposed Lower VSL	The Generator Owner failed to provide Fault recording capability at… Up to and including 10% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
	Proposed Moderate VSL	The Generator Owner failed to provide Fault recording capability at… More than 10% and up to and including 20% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
	Proposed High VSL	The Generator Owner failed to provide Fault recording capability at… More than 20% and up to 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
	Proposed Severe VSL	The Generator Owner failed to provide Fault recording capability at… More than 30% of its Generating Plants at and above 200 MVA Capacity and connected to a Bulk Electric System Element if Fault recording capability for that portion of the system is inadequate.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSLs are consistent with PRC-018-1 Requirement R2 that establishes the same increments within the VSLs: **Lower**: The responsible entity is non-compliant in that no more than 10% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3. **Moderate**: The responsible entity is non-compliant in that more than 10% but less than or equal to 20% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3. **High**: The responsible entity is non-compliant in that more than 20% but less than or equal to 30% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3. **Severe**: The responsible entity is non-compliant in that more than 30% of the DME devices were not installed in accordance with its Regional Reliability Organization's installation requirements as defined in PRC-002 Requirements 1 through 3.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is not binary and does not violate this guideline Guideline 2b: the VSL is gradated properly. The violation gradations should not overlap.

	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL assignment is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R5		
R5	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	The Transmission Owner or Generator Owner failed to record for the Faults… Up to and including 10% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
	Proposed Moderate VSL	The Transmission Owner or Generator Owner failed to record for the Faults… More than 10% and up to and including 20% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.

	Proposed High VSL	The Transmission Owner or Generator Owner failed to record for the Faults… More than 20% and up to and including 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
	Proposed Severe VSL	The Transmission Owner or Generator Owner failed to record for the Faults… More than 30% of the total set of parameters, which is the product of the total number of monitored Elements and the number of parameters listed in 5.1 through 5.5.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-1 Requirement R2 sub-requirement R2.1.3 contains the electrical quantities to be recorded for each monitored element. Violating this requirement qualifies for a Level 2 Non-Compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is not binary and does not violate this guideline Guideline 2b: the VSL is gradated properly. The violation gradations should not overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R6		
R6	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.

	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	The Transmission Owner or Generator Owner failed … To provide Fault recording capability for up to and including 10% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for up to 2 locations.
	Proposed Moderate VSL	The Transmission Owner or Generator Owner failed … To provide Fault recording capability for more than 10% and up to and including 20% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than two (2) and up to and including five (5) locations.
	Proposed High VSL	The Transmission Owner or Generator Owner failed … To provide Fault recording capability for more than 20% and up to and including 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than five (5) and up to and including ten (10) locations.
	Proposed Severe VSL	The Transmission Owner or Generator Owner failed … To provide Fault recording capability for more than 30% of the total set of requirements, which is the product of the total number of monitored Elements and the total number of capabilities identified in 6.1 through 6.2. OR Failed to document additional triggers or deviations from the settings stipulated in 6.3 through 6.4 for more than ten (10) locations.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-1 Requirement R2 sub-requirement R2.1.3 contains the electrical quantities to be recorded for each monitored element. Violating this requirement qualifies for a Level 2 Non-Compliance.
	FERC VSL G2	Guideline 2a: the VSL is not binary

	Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: the VSL is gradated properly. The violation gradations should not overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R7		
R7	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and

		control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	The Reliability Coordinator failed to establish its area's requirements for… Up to and including 10% of the required DDR coverage for its area as per 7.1and 7.2.
	Proposed Moderate VSL	The Reliability Coordinator failed to establish its area's requirements for… More than 10% and up to and including 20% of the required DDR coverage for its area as per 7.1 and 7.2.
	Proposed High VSL	The Reliability Coordinator failed to establish its area's requirements for… More than 20% and up to and including 30% of the required DDR coverage for its area as per 7.1 and 7.2.
	Proposed Severe VSL	The Reliability Coordinator failed to establish its area's requirements for… More than 30% of the required DDR coverage for its area as per 7.1 and 7.2.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-1 Requirement R2 sub-requirement R2.1.3 contains the electrical quantities to be recorded for each monitored element. Violating this requirement qualifies for a Level 2 Non-Compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: the VSL is gradated properly. The violation gradations should not overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The VSL is based on a single violation.

	Cumulative Number of Violations	

PRC-002-NPCC-01 VRF and VSL Justifications--R8		
R8	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	Not applicable.
	Proposed Moderate VSL	Not applicable.
	Proposed High VSL	Not applicable.
	Proposed Severe VSL	The Reliability Coordinator failed to specify that DDRs installed… Function as continuous recorders.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-1 Requirement R2 sub-requirement R2.1.3 contains the electrical quantities to be recorded for each monitored element. Violating this requirement qualifies for a Level 2 Non-Compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the	Guideline 2a" VSL is binary and the single level is severe.

	Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R9		
R9	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*

	Proposed Lower VSL	Not applicable.
	Proposed Moderate VSL	Not applicable.
	Proposed High VSL	Not applicable.
	Proposed Severe VSL	The Reliability Coordinator failed to specify that DDRs are installed without… The capabilities listed in 9.1 through 9.3.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-1 Requirement contains the DDR Requirements and violating Requirement R3 is a level 2 non-compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is binary and does not violate this guideline Guideline 2b: the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
PRC-002-NPCC-01 VRF and VSL Justifications--R10		
R10	Proposed VRF	*Medium*
	NERC VRF Discussion	

	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	Not applicable.
	Proposed Moderate VSL	Not applicable.
	Proposed High VSL	Not applicable.
	Proposed Severe VSL	The Reliability Coordinator failed to ensure that the quantities listed in 10.1 through 10.5 are monitored or derived…Where DDRs are installed.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-1 Requirement contains the DDR Requirements and violating Requirement R3 is a level 2 non-compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is binary and does not violate this guideline Guideline 2b: the VSL does not contain ambiguous language.
	FERC VSL G3 Violation Severity Level	The proposed VSL is consistent with the corresponding requirement.

	Assignment Should Be Consistent with the Corresponding Requirement	
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R11		
R11	Proposed VRF	*Lower*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The other requirements within the proposed standard that are administrative in nature are consistently assigned a Lower VRF.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and the proposed VSL for Requirement R11 is assigned a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The VRF assignment for Requirement R11 is consistent with the NERC definition of a Lower VRF namely that the Requirement is administrative in nature.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for… Up to two (2) facilities within the Reliability Coordinator's area that have a DDR.
	Proposed Moderate VSL	The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for… More than two (2) and up to five (5) facilities within the Reliability Coordinator's area that have a DDR.

	Proposed High VSL	The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for… More than five (5) and up to ten (10) facilities within the Reliability Coordinator's area that have a DDR.
	Proposed Severe VSL	The Reliability Coordinator failed to document and report to the Regional Entity upon request additional settings and deviations from the required trigger settings described in R9 and the required list of monitored quantities as described in R10 for… More than ten (10) facilities within the Reliability Coordinator's area that have a DDR.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-1 Requirement contains the DDR Requirements and violating Requirement R3 is a level 2 non-compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is not binary and does not violate this guideline Guideline 2b: the VSL is gradated properly. The violation gradations should not overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding Requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R12		
R12	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.

	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-002-1 Requirement R5 The RRO is to provide the DDR requirements to the TOs and GOs. PRC-002-1 does not have an approved VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Requirement R12 references Requirement R9 and both Requirements are assigned a Medium VRF.
	Proposed Lower VSL	Not applicable.
	Proposed Moderate VSL	Not applicable.
	Proposed High VSL	Not applicable.
	Proposed Severe VSL	The Reliability Coordinator failed to specify to the Transmission Owners and Generator Owners its DDR requirements including the DDR setting triggers established in R9 but missed… Established setting triggers.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-1 Requirement contains the DDR Requirements and violating Requirement R3 is a level 2 non-compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is binary and does not violate this guideline Guideline 2b: the VSL does not contain ambiguous language
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.

	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R13		
R13	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance

		monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R2 (The Transmission Owner and Generator Owner shall each install DMEs in accordance with its Regional Reliability Organization's installation requirements (reliability standard PRC-002 Requirements 1 through 3). establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Requirement R13 references Requirement R12 and both Requirements are assigned a Medium VRF.
	Proposed Lower VSL	The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for… Up to and including 10% of the requirement set of the Reliability Coordinator's request to install DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.
	Proposed Moderate VSL	The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for… More than 10% and up to 20% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.
	Proposed High VSL	The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for… More than 20% and up to 30% of the requirement set requested by the Reliability Coordinator for installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR.
	Proposed Severe VSL	The Transmission Owner or Generator Owner failed to comply with the Reliability Coordinator's request installing the DDR in accordance with R12 for… More than 30% of the requirement set requested by the Reliability Coordinator and installing DDRs, with the requirement set being the total number of DDRs requested times the number of setting triggers specified for each DDR OR The Reliability Coordinator, Transmission Owners, and Generator Owners failed to mutually agree on an implementation schedule.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-002-1 Requirement contains the DDR Requirements and violating Requirement R3 is a level 2 non-compliance.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the	Guideline 2a VSL is not binary and does not violate this guideline Guideline 2b: the VSL is gradated properly. The violation gradations should not

	Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R14		
R14	Proposed VRF	*Medium*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The requirements in the proposed standard that pertain directly to the disturbance monitoring equipment have been assigned a Medium Violation Risk Factor.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R6 (The Transmission Owner and Generator Owner shall each have a maintenance and testing program for those DMEs that includes the specifications in R6.1 through R6.2) establishes a Lower VRF and while the proposed standard assigns it a Medium VRF the proposal is in line with the NERC definition of a Medium VRF and not a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation Not applicable
	Proposed Lower VSL	The Transmission Owner or Generator Owner… Established a maintenance and testing program for stand alone DME but provided incomplete data for any one (1) of 14.1 through 14.7.
	Proposed Moderate VSL	The Transmission Owner or Generator Owner… Established a maintenance and testing program for stand alone DME but provided incomplete data for more than one (1) and up to and including three (3) of 14.1 through 14.7.
	Proposed High VSL	The Transmission Owner or Generator Owner… Established a maintenance and testing program for stand alone DME but provided incomplete data for more than three (3) and up to and including six (6) of 14.1 through 14.7.
	Proposed Severe VSL	The Transmission Owner or Generator Owner… Did not establish any maintenance and testing program for DME; OR The Transmission Owner or Generator Owner established a maintenance and testing program for DME but did not provide any data that meets all of 14.1 through 14.7.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	**PRC-018-1 Requirement R6** establishes the following VSLs: **Lower** N/A **Moderate** N/A **High** The responsible entity is not compliant in that the maintenance and testing

		program for DMEs does not include one of the elements in R6.1 and 6.2. **Severe** The responsible entity is not compliant in that the maintenance and testing program for DMEs does not include any of the elements in R6.1 and 6.2. **PRC-018-1 Sub-requirement R6.1** establishes the following VSLs: **Lower** The responsible entity's DME maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for no more than 25% of the DME equipment. **Moderate** The responsible entity's DME maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 25% but less than or equal to 50% of the DME equipment. **High** The responsible entity's DME maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 50% but less than or equal to 75% of the DME equipment. **Severe** The responsible entity's DME maintenance and testing program was non-compliant in that documentation of maintenance and testing intervals and their basis was missing for more than 75% of the DME equipment. **PRC-018-1 Sub-requirement R6.2** establishes the following VSLs: **Lower** The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for no more than 25% of the DME equipment. **Moderate** The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for more than 25% but less than or equal to 50% of the DME equipment. **High** The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for more than 50% but less than or equal to 75% of the DME equipment. **Severe** The responsible entity's DME maintenance and testing program was non-compliant in that the summary of maintenance and testing procedures documentation was missing for more than 75% of the DME equipment.

	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is not binary and does not violate this guideline Guideline 2b: the VSL does not contain ambiguous language. Also, the VSL is gradated properly. The violation gradations should not overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R15		
R15	Proposed VRF	*Lower*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The other requirements within the proposed standard that are administrative in nature are consistently assigned a Lower VRF.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R4 The TO and GO shall provide Disturbance data recorded by DMEs in accordance with its RRO's requirements establishes a Lower VRF and the proposed VSL for Requirement R15 is assigned a Lower VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The VRF assignment for Requirement R15 is consistent with the NERC definition of a Lower VRF namely that the Requirement is administrative in nature.

	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for… Up to and including fifteen (15) days in meeting the requests of an entity, or entities in 15.1, or 15.2.
	Proposed Moderate VSL	The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for… More than fifteen (15) days but less than and including thirty (30) days in meeting the requests of an entity, or entities in 15.1 or 15.2.
	Proposed High VSL	The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for… More than 30 days but less than and including forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.
	Proposed Severe VSL	The Reliability Coordinator, Transmission Owner or Generator Owner provided recorded disturbance data from DMEs but was late for… More than forty-five (45) days in meeting the requests of an entity, or entities in 15.1 or 15.2.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-018-1 Requirement R4 establishes the following VSLs: **Lower** The responsible entity is not compliant in that it did not provide less than or equal to 10% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements. **Moderate** The responsible entity is not compliant in that it did not provide less than or equal to 20% but greater than 10% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements. **High** The responsible entity is not compliant in that it did not provide less than or equal to 30% but greater than 20% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements. **Severe** The responsible entity is not compliant in that it did not provide greater than 30% of the disturbance data (recorded by DMEs) in accordance with its Regional Reliability Organization's requirements.
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is not binary and does not violate this guideline Guideline 2b: the VSL does not contain ambiguous language:

	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.
PRC-002-NPCC-01 VRF and VSL Justifications--R16		
R16	Proposed VRF	*Lower*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The other requirements within the proposed standard that are administrative in nature are consistently assigned a Lower VRF.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-002-1 Requirement R4 The RRO establishes requirements for facility owners to report Disturbance data that includes sub-requirements R4.1 through R4.6. This requirement does not have an approved VRF.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The VRF assignment for Requirement R15 is consistent with the NERC definition of a Lower VRF namely that the Requirement is administrative in nature.
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit Up to and including two (2) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
	Proposed Moderate VSL	The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit More than two (2) and up to and including five (5) data files in a format that meets the applicable format requirements in 16.1 through 16.3
	Proposed High VSL	The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit More than five (5) and up to and including ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3.
	Proposed Severe VSL	The Reliability Coordinator, Transmission Owner or Generator Owner failed to submit More than ten (10) data files in a format that meets the applicable format requirements in 16.1 through 16.3
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the	Violating Requirement R4 of PRC-002-1 is a Level 1 Non-compliance.

	Unintended Consequence of Lowering the Current Level of Compliance	
	FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a VSL is not binary and does not violate this guideline Guideline 2b: the VSL is gradated properly. The violation gradations should not overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

PRC-002-NPCC-01 VRF and VSL Justifications--R17		
R17	Proposed VRF	*Lower*
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report System modeling and data exchange, synchronized data recorders.
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard The other requirements within the proposed standard that are administrative in nature are consistently assigned a Lower VRF.
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards PRC-018-1 Requirement R3 The TO and GO shall maintain and report to its RRO on request the data in R3.1 through R3.8. This requirement is assigned a Lower VRF. Requirement R17 establishes the same level.
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The VRF assignment for Requirement R15 is consistent with the NERC definition of a Lower VRF namely that the Requirement is administrative in nature.

	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *Not applicable*
	Proposed Lower VSL	The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request… Up to and including two (2) of the items in 17.1 through 17.8.
	Proposed Moderate VSL	The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request… More than two (2) and up to and including four (4) of the items in 17.1 to 17.8.
	Proposed High VSL	The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request… More than four (4) and up to and including six (6) of the items in 17.1 through 17.8.
	Proposed Severe VSL	The Reliability Coordinator, Transmission Owner or Generator Owner failed to maintain or provide to the Regional Entity , upon request… More than six (6) of the items in 17.1 through 17.8.
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	PRC-018-1 Requirement R3 VSLs: **Lower** The responsible entity was not compliant in that evidence that it maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for one of the elements in Requirements 3.1 through 3.8. **Moderate** The responsible entity was not compliant in that evidence that it maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for two or three of the elements in Requirements 3.1 through 3.8. **High** The responsible entity was not compliant in that evidence that it maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for four or five of the elements in Requirements 3.1 through 3.8. **Severe** The responsible entity was not compliant in that evidence that it maintained data on the DMEs installed to meet that region's installation requirements was missing or not reported for more than five of the elements in Requirements 3.1 through 3.8. The increments established by the VSL for Requirement R17 are consistent with the increments (increments of five) in sub-requirements PRC-018-1 R3.1 through R3.8.
	FERC VSL G2	Guideline 2a VSL is not binary and does not violate this guideline

	Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2b: the VSL is gradated properly. The violation gradations should not overlap.
	FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VLS is consistent with the corresponding requirement.
	FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation.

NERC's VRF Criteria:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an

unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC's VRF Guidelines:
VRF G1 – Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. From footnote 15 of the May 18, 2007 Order, FERC's list of critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System includes:

– Emergency operations
– Vegetation management
– Operator personnel training
– Protection systems and their coordination
– Operating tools and backup facilities
– Reactive power and voltage control
– System modeling and data exchange
– Communication protocol and facilities
– Requirements to determine equipment ratings
– Synchronized data recorders
– Clearer criteria for operationally critical facilities
– Appropriate use of transmission loading relief.

VRF G2 – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

VRF G3 – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

VRF G4 – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

VRF G5 –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC's Criteria for VSLs:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC's VSL Guidelines:
VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance (Compare the VSLs to any prior Levels of Non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when Levels of Non-compliance were used.)

VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties (A violation of a "binary" type requirement must be a "Severe" VSL. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)

VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)

VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations (. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.)