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| NOGRR Number | [255](https://www.ercot.com/mktrules/issues/NOGRR255) | NOGRR Title | High Resolution Data Requirements |
| Date of Decision | | April 15, 2024 | |
| Action | | Recommended Approval | |
| Timeline | | Normal | |
| Estimated Impacts | | Cost/Budgetary: None  Project Duration: No project required | |
| Proposed Effective Date | | First of the month following Public Utility Commission of Texas (PUCT) approval | |
| Priority and Rank Assigned | | Not applicable | |
| Nodal Operating Guide Sections Requiring Revision | | 6.1, Disturbance Monitoring Requirements  6.1.1, Introduction  6.1.1.1, Applicability (new)  6.1.2, Fault Recording and Sequence of Events Recording Equipment  6.1.2.1. Fault Recording Requirements  6.1.2.2 Fault Recording and Sequence of Events Recording Equipment Location Requirements  6.1.2.3, Fault Recording and Sequence of Events Recording Data Requirements  6.1.2.4, Fault Recording and Sequence of Events Recording Data Retention and Reporting Requirements  6.1.3, Phasor Measurement Recording Equipment Including Dynamic Disturbance Recording Equipment  6.1.3.1, Dynamic Disturbance Recording Equipment Requirements (new)  6.1.3.1, Recording and Triggering Requirements  6.1.3.2, Location Requirements  6.1.3.3, Data Recording and Redundancy Requirements  6.1.3.4, Data Retention and Data Reporting Requirements  6.1.3.2, Phasor Measurement Unit Requirements (new)  6.1.3.2.1, Phasor Measurement Unit Recording Requirements (new)  6.1.3.2.2, Phasor Measurement Unit Location Requirements (new)  6.1.3.2.3, Phasor Measurement Unit Data Recording and Redundancy Requirements (new)  6.1.3.2.4, Phasor Measurement Unit Data Retention and Data Reporting Requirements (new)  6.1.4, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs) (new)  6.1.4.1, Fault Recording and Sequence of Events Recording Equipment Requirements (new)  6.1.4.1.1, Sequence of Events Recording Data Requirements (new)  6.1.4.1.2, Fault Recording Data and Triggering Requirements (new)  6.1.4.3, Phasor Measurement Unit Equipment Requirements (new)  6.1.4.4, Data Retention and Data Reporting Requirements of Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Equipment (new)  6.1.4, Maintenance and Testing Requirements  6.1.5, Equipment Reporting Requirements  6.1.6, Review Process  8, Attachment M, Selecting Buses for Capturing Sequence of Events Recording and Fault Recording Data | |
| Related Documents Requiring Revision/Related Revision Requests | | None | |
| Revision Description | | This Nodal Operating Guide Revision Request (NOGRR) establishes high resolution data requirements. | |
| Reason for Revision | | [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 1 – Be an industry leader for grid reliability and resilience  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 2 - Enhance the ERCOT region’s economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers  [Strategic Plan](https://www.ercot.com/files/docs/2023/08/25/ERCOT-Strategic-Plan-2024-2028.pdf) Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission  General system and/or process improvement(s)  Regulatory requirements  ERCOT Board and/or PUCT Directive  *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)* | |
| Justification of Reason for Revision and Market Impacts | | ERCOT has recently experienced several generation ride-through failure events and model quality issues, highlighting the need for high resolution data to perform model validation and event analysis. The resolution of Supervisory Control and Data Acquisition (SCADA) data (4-10 sec) is insufficient and, therefore, ERCOT needs high resolution data to help ensure ERCOT System reliability. The North American Electric Reliability Corporation (NERC) 2022 Odessa Disturbance report highlighted the need for such data and ERCOT has identified several updates to the disturbance monitoring requirements in the Nodal Operating Guide to support this important work. ERCOT proposes restructuring the requirements for clarity and separating Inverter-Based Resource (IBR) requirements from the requirements for other facilities.  ERCOT has observed several issues when requesting high resolution data. There have been an unacceptable number of requests in which the Market Participant could not provide important data because recording equipment was either not properly maintained or verified as operational. Thus, ERCOT had no access to valuable data needed to troubleshoot a ride-through failure. In response, ERCOT proposes requirements for equipment maintenance and testing to ensure availability of a minimum level of data.  Additionally, there have been multiple instances of Market Participants having no data due to inadequate trigger settings on recording equipment. ERCOT proposes additional clarity and consistency on trigger settings for digital fault recorders, sequence of events recording equipment, dynamic disturbance recording equipment, and phasor measurement units.  ERCOT also proposes additional requirements for IBRs aligned with Table 19 in the new Institute of Electrical and Electronics Engineers (IEEE) 2800-2022 Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems (“IEEE 2800-2022 standard”) to have consistent specification for new and replaced recording equipment for IBRs.  ERCOT proposes new disturbance monitoring requirements for Loads greater than 75 MVA and Load or Generation Resources 20 MVA and above that experience ride-through failures, and new requirements for streaming phasor measurement unit data to ERCOT for certain locations.  The proposed revisions will also help ERCOT comply with NERC Reliability Standard PRC-002-4, Disturbance Monitoring and Reporting Requirements, which goes into effect on April 1, 2024. | |
| ROS Decision | | On 8/3/23, ROS voted unanimously to table NOGRR255 and refer the issue to the System Protection Working Group (SPWG), the Dynamics Working Group (DWG) and the Inverter-Based Resource Working Group (IBRWG). All Market Segments participated in the vote.  On 2/1/24, ROS voted to recommend approval of NOGRR255 as amended by the 1/30/24 CEHE comments as revised by ROS. There was one abstention from the Independent Generator (Luminant) Market Segment. All Market Segments participated in the vote.  On 3/7/24, ROS voted to endorse and forward to TAC the 2/1/24 ROS Report and 6/29/23 Impact Analysis for NOGRR255. There was one abstention from the Independent Generator (Luminant) Market Segment. All Market Segments participated in the vote. | |
| Summary of ROS Discussion | | On 8/3/23, participants discussed that ROS working groups began discussing NOGRR255 before formal assignment, that a special SPWG meeting would be scheduled, and that NERC recently published drafts for updated standards. Participants determined to continue further discussions at fewer working groups with joint meetings to minimize strain on resources.  On 2/1/24, participants reviewed desktop edits proposed for the 1/30/24 CEHE comments and discussed whether NOGRR255 should remain tabled for further review by the IBRWG.  On 3/7/24, participants reviewed the 6/29/23 Impact Analysis. | |
| TAC Decision | | On 3/27/24, TAC voted unanimously to table NOGRR255. All Market Segments participated in the vote.  On 4/15/24, TAC voted unanimously to recommend approval of NOGRR255 as recommended by ROS in the 3/7/24 ROS Report as amended by the 4/11/24 Luminant comments. All Market Segments participated in the vote. | |
| Summary of TAC Discussion | | On 3/27/24, TAC reviewed the items below. Some participants expressed concern that language bifurcating IBR and non-IBR requirements should be further clarified, and determined to table NOGRR255 for additional comments.  On 4/15/24, participants reviewed the 4/11/24 Luminant comments. | |
| TAC Review/Justification of Recommendation | | Revision Request ties to Reason for Revision as explained in Justification  Impact Analysis reviewed and impacts are justified as explained in Justification  Opinions were reviewed and discussed  Comments were reviewed and discussed (if applicable)  Other: (explain) | |

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| Opinions | |
| Credit Review | Not applicable |
| Independent Market Monitor Opinion | IMM has no opinion of NOGRR255. |
| ERCOT Opinion | ERCOT supports approval of NOGRR255. |
| ERCOT Market Impact Statement | ERCOT Staff has reviewed NOGRR255 and believes it has a positive market impact as it provides ERCOT with high resolution data for model validation and event analysis to ensure ERCOT System reliability, and assists compliance with NERC Reliability Standard PRC-002-4, Disturbance Monitoring and Reporting Requirements, which goes into effect April 1, 2024. |

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| Market Segment | Not Applicable |

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| **Comments Received** | |
| **Comment Author** | **Comment Summary** |
| Oncor 102723 | Proposed changes to triggering requirements; clarified location requirements; addressed implementation schedule for requirements; removed requirements regarding transmission of phasor measurement unit data and recommended a separate revision request; opined that model verification tasks can be completed to a practical extent with currently available telemetered data |
| ERCOT 110123 | Clarified fault recording requirements; added phase under-voltage that would trigger Under-Voltage Load Shed (UVLS); adjusted frequency triggers; modified implementation language; agreed to defer proposed location requirements removed by the 10/27/23 Oncor comments |
| EDFR 120423 | Proposed that IBR units operated prior to January 1, 2017, the IEEE C37.118.1-2005 be used as an alternative to IEEE C37.118.1-2011; recommended that ERCOT prioritize the plant level data over the IBR unit data, and develop a phased-in implementation for sequence of events data recording requirements |
| SPC and Invenergy 120423 | Recommended that NOGRR255 remain tabled until after NERC finalizes PRC-028; proposed excluding IBR units from certain requirements; recommended requiring installation of recording devices and global positioning system-based clocks at the longest feeder, rather than on each feeder; proposed further alignment of record length, clock accuracy, and rolling data retention periods with PRC-028 |
| AEPSC 120423 | Proposed revisions to Section 8, Attachment M, to align with PRC-002-4 and PRC-002-5; proposed revisions to implementation timelines and reporting requirements |
| Tesla 120423 | Recommended lowering requirements for IBR unit-level time synchronization and fault record data for Resources installed prior to January 1, 2026; proposed revisions to allow IBR units themselves, rather than external equipment, to meet certain requirements; suggested additional data format Comma Separated Value (CSV) |
| Engie 120723 | Noted limited resources available to complete install work associated with NOGRR255 and NOGRR245, Inverter-Based Resource (IBR) Ride-Through Requirements; expressed concern as particularly challenging the requirement to record fault data from individual IBR units; recommended Request For Information on the ability of existing IBR units to comply without retrofit |
| APA 122023 | Noted that original equipment manufacturers or other software/hardware vendors will have to develop the necessary equipment and software to meet the requirements of NOGRR255 as solutions do not currently exist; recommended NOGRR255 remain tabled to allow for alignment with the final NERC PRC-028 standard |
| ERCOT 010424 | Noted Federal Energy Regulatory Commission (FERC) Order 901, paragraph 85 highlighted the urgency and impact of data contemplated in NOGRR255 and urged its adoption not be delayed; reiterated ERCOT’s agreement to defer language regarding certain inverter unit-level requirements in order to advance the remainder of NOGRR255; proposed clarifications and refinements to language proposed in other comments |
| CEHE 010524 | Revised timelines for equipment installation; recommended changes to recording equipment and phasor measurement unit location requirements; and modified trigger criterion |
| CEHE 013024 | Clarified the 1/5/24 CEHE comments |
| Luminant 032224 | Proposed that language that applies generally to both IBRs and traditional generators defer to PRC-002 requirements, and offered revisions; and expressed concern for retroactive requirements |
| ERCOT 032624 | Noted objections to elements of the 3/22/24 Luminant comments and urged TAC to recommend approval of NOGRR255 as recommended by ROS in the 3/7/24 ROS Report |
| Luminant 041124 | Offered compromise language with an intent to reconcile the majority of differences between the 3/22/24 Luminant comments and objections raised in the 3/26/24 ERCOT comments |

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| **Market Rules Notes** |

None

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| Proposed Guide Language Revision |

6.1 Disturbance Monitoring Requirements

(1) Disturbance monitoring equipment includes sequence of events recording equipment, fault recording equipment, dynamic disturbance recording equipment, and phasor measurement units.

(a) Sequence of events equipment includes any device capable of recording circuit breaker position (open/close) or binary status points that allows analysis of the root cause of a dynamic disturbance based on the order of occurrence of events.

(b) Fault recording equipment captures data associated with an abnormal event on the system, such as phase-to-phase faults, phase-to-ground faults, etc. and includes digital fault recorders, certain protective relays, fault recording-capable meters, and some dynamic disturbance recording equipment.

(c) Dynamic disturbance recording equipment captures incidents that represent behavior of the power system during dynamic events, such as low frequency oscillations, abnormal under/over frequency, voltage excursions and system-wide transients. Some dynamic disturbance recording equipment can also serve as a phasor measurement unit.

(d) Phasor measurement involves measuring time synchronized phasors, frequency, and rate of change of frequency of the power system with accuracy in the order of one microsecond and is typically performed by a digital relay, fault recording equipment or dedicated phasor measurement unit.

6.1.1 Introduction

(1) Disturbance monitoring is necessary to:

(a) Determine performance of the ERCOT System;

(b) Determine effectiveness of protective relaying systems;

(c) Verify ERCOT System models;

(d) Determine causes of ERCOT System disturbances (trips, faults, and protective relay system actions);

(e) Determine causes of Generation Resource and Energy Storage Resource (ESR) ride-through performance failures and loss of Load events; and

(f) Meet the requirements of North American Reliability Corporation (NERC) Reliability Standards.

(2) To ensure ERCOT has adequate data for these activities, ERCOT establishes the disturbance monitoring requirements and procedures in these Operating Guides for the following:

(a) Fault recording, sequence of events recording, phasor measurement, and dynamic disturbance recording equipment owners; and

(b) Transmission Service Providers (TSPs) and Resource Entities with equipment for recording Geomagnetic Disturbance (GMD) data, including Geomagnetically-Induced Current (GIC) monitors and/or magnetometers for recording geomagnetic field data.

6.1.1.1 Applicability

(1) Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment, and its subsections apply to all ESRs, all Generation Resource Facilities that are not Inverter-Based Resource (IBR) Facilities, and the interconnecting TSP or Distribution Service Provider (DSP) for such Facilities.

(2) Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment, and its subsections apply to all ESRs, all Generation Resource Facilities that are not IBR facilities, and to all TSPs and DSPs.

(3) Section 6.1.4, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs), and its subsections apply to IBR Facilities.

6.1.2 Fault Recording and Sequence of Events Recording Equipment

(1) Fault recording equipment includes digital fault recorders, certain protective relays, meters with fault recording capability meeting the associated requirements in this Section.

(2) Sequence of events recording equipment includes any device capable of recording circuit breaker position (open/close) or other binary points meeting the associated requirements in this Section.

(3) Required fault recording and sequence of events recording equipment shall, at a minimum, be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative to within +/- 2 milliseconds of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).6.1.2.1 Fault Recording Requirements

(1) Fault recording equipment shall meet the following requirements:

(a) Either give continuous fault recording data or triggering for the following:

(i) Neutral (residual) overcurrent of 0.2 p.u. or less of rated current transformer secondary current or the equivalent of 200-500A primary current;

(ii) Any phase under-voltage below 0.85 p.u. for two cycles or longer;

(iii) Any phase overcurrent above the equipment’s maximum emergency current rating, or protective relay tripping for all protection groups;

(iv) Deviations to the above triggering minimum requirements must be reviewed and approved by ERCOT.

(v) Additional triggering beyond the minimums above are allowed and do not require review and approval by ERCOT.

(b) Minimum recording rate of 16 samples per cycle; and

(c) A single record or multiple records that include a pre-trigger record length of at least two cycles and a total record length of at least 60 cycles for the same trigger point.

(i) For existing fault recording equipment installed prior to June 1, 2024 that cannot record a total record length of at least 60 cycles and meet the other recording rate and retention period requirements without upgrading or replacing the equipment, the fault recording equipment must, at a minimum, meet a total record length of at least 30 cycles until such time the facility owner must upgrade or replace the equipment.

6.1.2.2 Fault Recording and Sequence of Events Recording Equipment Location Requirements

(1) The location criteria listed below apply to Transmission Facilities operated at or above 100 kV unless otherwise specified. The Facility owner, whether a Transmission Facility owner or Generation Resource owner, shall, as applicable, install fault recording and sequence of events recording equipment at the following locations, at a minimum:

(a) Locations identified by the Transmission Facility owner utilizing the methodology in Section 8, Attachment M, Selecting Buses for Capturing Sequence of Events Recording and Fault Recording Data;

(b) Additional locations selected at the Transmission Facility owner’s discretion, utilizing the methodology in Section 8, Attachment M;

(c) Locations operating at or above 60 kV, as defined below.

(i) Interconnections with Control Areas outside the ERCOT Region;

(ii) Substations where electrical transfers can be made between the ERCOT Control Area and a Control Area outside the ERCOT Region;

(iii) All switchyards owned by a Generation Resource or ESR connected to the ERCOT System with an aggregated gross generating nameplate capacity above 100 MVA.

(d) For locations that have experienced an abnormal trip or immediate Load change greater than or equal to 20 MW (including if caused by a Distribution Generation Resource (DGR), Distribution Energy Storage Resource (DESR), or Settlement Only Distribution Generator (SODG)) after a fault:

(i) ERCOT may require the installation of fault recording and sequence of events recording equipment;

(ii) The interconnecting Transmission Service Provider (TSP) or Distribution Service Provider (DSP) shall ensure recording equipment is installed;

(iii) A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;

(iv) The recording equipment will be installed as soon as practicable, but no longer than 18 months after ERCOT notifies the TSP or DSP of the need to install the equipment, unless ERCOT provides an extension; and

(v) If the TSP or DSP determines that the recording equipment installation is infeasible due to engineering, technical or operational reasons, it will provide such rationale to ERCOT.

(e) For any Load consisting of one or more Facilities at a single site with an aggregate peak Demand greater than or equal to 75 MW behind one or more Service Delivery Points:

(i) ERCOT may require the installation of fault recording and sequence of events recording equipment;

(ii) The interconnecting TSP or DSP shall ensure the recording equipment is installed;

(iii) A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;

(iv) The recording equipment will be installed as soon as practicable, but no longer than 18 months after ERCOT notifies the TSP or DSP of the need to install the equipment, unless ERCOT provides an extension; and

(v) If the TSP or DSP determines that the recording equipment installation is infeasible due to engineering, technical or operational reasons, it will provide such rationale in writing to ERCOT.

(2) Transmission Facility owners or Generation Facility owners shall install the applicable fault recording and sequence of events recording equipment identified in paragraph (1) above as soon as practicable.

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| ***[NOGRR255: Replace paragraph (2) above with the following no earlier than <Insert Date at least two years after PUCT approval> and renumber accordingly:]***  (2) Facility owners shall have at least 50% of the new fault recording and sequence of events recording equipment identified in paragraph (1) above installed. |

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| ***[NOGRR255: Delete paragraph (2) no earlier than <Insert Date at least four years after PUCT approval> and renumber accordingly:]*** |

(3) For any Generation Resource or ESR that has not installed fault recording or sequence of events recording equipment and experiences an unexpected trip or significant reduction in output in response to a system disturbance after a fault for which it is unable to determine the cause, ERCOT may require the installation of fault recording and sequence of events recording equipment consistent with the requirements of Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment. The Generation Resource or ESR owner shall install the fault recording and sequence of events recording equipment at an ERCOT-specified location as soon as practicable but no longer than 18 months after the date that ERCOT notifies the Facility owner it must install the equipment, unless the requestor provides an extension.

6.1.2.3 Fault Recording and Sequence of Events Recording Data Requirements

(1) Each Transmission Facility owner and Generation Resource owner shall have fault recording data to determine the following electrical quantities for each triggered fault recording for the locations specified in Section 6.1.2.2, Fault Recording and Sequence of Events Recording Equipment Location Requirements:

(a) Phase-to-neutral voltage for each phase of each specified bus with two sets of substation voltage measurements for breaker-and-a-half and ring bus substation configurations and one set of substation voltage measurements for each bus in other substation configurations;

(b) For transmission lines, each phase current and neutral (residual) current; and

(c) For transformers with a low-side operating voltage of 100kV or above, each phase current and the neutral (residual) current. These phase currents can be from either the high-side or low-side of the transformer.

(2) Each Transmission Facility owner and Generation Resource owner shall have sequence of events recording data per the following requirements:

(a) Circuit breaker position (open/close) for each circuit breaker it owns associated with the required monitored elements and connected directly to the transmission buses identified in paragraphs (1)(a) and (1)(b) of Section 6.1.2.2; and

(b) The following data as either part of the sequence of events recording data or fault recording digital status data:

(i) Circuit breaker position for each circuit breaker that it owns associated with monitored generator interconnects, transmission lines, and transformers;

(ii) Carrier transmitter control status (i.e. start, stop, keying) for associated transmission lines; and

(iii) Carrier signal receive status for associated transmission lines.

(3) Each Generation Resource owner and ESR owner shall have the following fault recording data for each triggered fault recording to determine:

(a) Time stamp;

(b) Phase-to-neutral voltage for each phase on low or high side of the Main Power Transformer (MPT);

(c) Each phase current and the residual or neutral current on low or high side of the MPT;

(d) If applicable, active and reactive power on low or high side of the MPT;

(e) If applicable, frequency and rate-of-change-of-frequency (df/dt) data for at least one generator-interconnected bus measurement;

(f) If applicable, dynamic reactive device input/output such as voltage, current, and frequency; and

(g) Applicable binary status.

(4) If the fault recorder does not directly measure the values in paragraphs (3)(d) through (3)(f) above, then dynamic disturbance recording or phasor measurement unit data is acceptable so long as data of sufficient resolution is available to validate dynamic models, identify protection system actions, and identify the cause of a ride-through failure.

(5) For each requested Facility identified by ERCOT in paragraphs (1)(d) and (1)(e) in Section 6.1.2.2, the interconnecting TSP or DSP shall have the following fault recording and sequence of events recording data for the identified Load elements to determine:

(a) Phase-to-neutral voltage for each phase of the transmission bus serving the Load, or other ERCOT approved voltages;

(b) Each phase current and neutral current for each Load terminal, or other ERCOT approved currents; and

(c) Circuit breaker status for those transmission circuit breakers directly associated with the Load terminals.

6.1.2.4 Fault Recording and Sequence of Events Recording Data Retention and Reporting Requirements

(1) Each Transmission Facility owner and Generation Resource owner shall, upon request, provide to ERCOT fault recording and sequence of events recording data for the Transmission Elements identified in these requirements as follows:

(a) Data shall be maintained and retrievable for at a minimum:

(i) Twenty calendar days, including the day the data was recorded, for fault recording and sequence of events recording equipment installed on or replaced after June 1, 2024;

(ii) Ten calendar days, including the day the data was recorded, for fault recording and sequence of events recording equipment installed prior to June 1, 2024;

(b) Data subject to paragraph (1)(a) above will be provided within seven calendar days of request unless the requestor grants an extension;

(c) Sequence of events recording data will be provided in ASCII Comma Separated Value (CSV) format as follows: Date, Time, Local Time Code, Substation, Device, State;

(d) Fault recording data that is not calculated will be provided in electronic files formatted in conformance with Institute of Electrical and Electronic Engineers (IEEE) C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later;

(e) Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later; and

(f) If available, fault recording data may be provided in electronic files in SEL ASCII event report (.EVE), compressed ASCII (.CEV), or Motor Start Report (.MSR) in both raw and filtered format in addition to the data required above.

(2) The Transmission Facility owner and Generation Resource owner providing the requested fault recording and sequence of events recording data to ERCOT, the NERC Regional Entity, or NERC shall store the data for at least three years from the date the data was created.

6.1.3 Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment

(1) Phasor measurement recording equipment includes all dynamic disturbance recording equipment with phasor measurement recording capability that meets the requirements in Section 6.1.3.1, Recording and Triggering Requirements, and 6.1.3.3, Data Recording and Redundancy Requirements. All new or replaced dynamic disturbance recording equipment installed after June 1, 2024 shall function as or provide phasor measurement unit(s) and meet requirements in Section 6.1.3.1.2, Location Requirements. If an existing trigger based dynamic disturbance recording equipment fails to record and provide data more than one time in a rolling 36 month period, ERCOT may require it to be replaced with a phasor measurement recording capability that meets the requirements in Section 6.1.3.1, Recording and Triggering Requirements, and 6.1.3.3, Data Recording and Redundancy Requirements.  In such instances, ERCOT would notify the facility owner and the facility owner shall install the new equipment within 18 months.

(2) Dynamic disturbance recording equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with sub-cycle (+/-1 microsecond) timing accuracy and performance.

**6.1.3.1 Dynamic Disturbance Recording Equipment Requirements**

**6.1.3.1.1 Recording and Triggering Requirements**

(1) Dynamic disturbance recording equipment shall:

(a) Have either continuous data recording or triggering for at least the following:

(i) Any phase under-voltage below 0.85 p.u. for two cycles or longer;

(ii) Phase under-voltage that would trigger Under-Voltage Load Shed (UVLS);

(iii) Any phase over-voltage greater than 1.15 p.u. for two cycles or longer;

(iv) Frequency below 59.5 Hz or above 60.5 Hz; and

(v) Frequency rate of change for low frequency of -0.08125 Hz/sec or high frequency of 0.125 Hz/sec;

(vi) ERCOT must review and approve any requested deviations from the above-referenced requirements.

(vii) Additional triggering in excess of the minimums set forth in paragraph (a) above are permitted and do not require ERCOT’s review and approval.

(b) Record lengths of at least three minutes;

(c) A minimum output recording rate of 30 samples per second; and

(d) A minimum input sampling rate of 960 samples per second.

***6.1.3.1.2 Dynamic Disturbance Recording Equipment Location Requirements***

(1) ERCOT shall identify and provide notification to Facility owners who shall install and maintain dynamic disturbance recording equipment at the following locations:

(a) A Generation Resource(s) that is not an IBR with:

(i) Gross individual nameplate rating greater than or equal to 500 MVA; or

(ii) Gross individual nameplate rating greater than or equal to 300 MVA if the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA;

(b) Any Transmission Element part of a stability-related (angular or voltage) system operating limit;

(c) Each terminal of a high-voltage, direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current side of a converter;

(d) One or more Transmission Elements part of an Interconnection Reliability Operating Limit (IROL); and

(e) Any one Transmission Element within a major voltage sensitive area as defined by an area with an in-service UVLS program.

(2) ERCOT shall identify, and notify Facility owners of, a minimum dynamic disturbance recording coverage, including Transmission Elements identified above, of a least:

(a) One Transmission Element; and

(b) One Transmission Element per 3,000 MW of ERCOT’s historical simultaneous peak Demand.



***6.1.3.1.3 Dynamic Disturbance Recording Data Recording and Redundancy Requirements***

(1) Recorded electrical quantities shall determine the following:

(a) For Transmission Facilities meeting the requirements in Section 6.1.3.1.2, Location Requirements:

(i) Phase-to-neutral voltage magnitude/angle data for each phase from at least two distinct transmission level element measurement points;

(ii) Single phase current magnitude/angle data for each phase from at least two distinct transmission lines; and

(iii) Frequency and rate-of-change-of-frequency (df/dt) data for at least two Transmission Element measurement points.

(b) For Generation Resource owner locations meeting the requirements in Section 6.1.3.1.2:

(i) Phase-to-neutral voltage, or phase-to-phase voltage magnitude/angle data for each phase from at least one generator-interconnected bus measurement point;

(ii) Single phase current magnitude/angle data for each phase from each interconnected generator on the high or low side of a MPT;

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| [NOGRR227: Replace item (ii) above with the following upon system implementation of NPRR973:]  (ii) Single phase current magnitude/angle data for each phase from each interconnected generator on the high or low side of a Main Power Transformer (MPT); |

(iii) Active and reactive power on low or high side of the MPT;

(iv) Frequency and df/dt data for at least one generator-interconnected bus measurement; and

(v) If applicable, dynamic reactive device input/output such as voltage, current, and frequency.

6.1.3.1.4 Dynamic Disturbance Recording Data Retention and Data Reporting Requirements

(1) A Market Participant required to have and maintain data regarding electrical quantities shall maintain and retain that data, at a minimum:

(a) A rolling ten calendar day period for all data;

(b) At least three years for event data used for model validation in accordance with NERC Reliability Standards; and

(c) At least three years for event data provided to ERCOT, the NERC Regional Entity, or NERC via written request recorded in the context of an event analysis or review.

(2) Each affected Market Participant shall provide to ERCOT, upon request, dynamic disturbance recording data as follows:

(a) Data must be retrievable for ten calendar days, including the day the data was recorded;

(b) Data subject to paragraph (2)(a) above within seven calendar days of a request unless the requestor grants an extension;

(c) Dynamic disturbance recording data in electronic files formatted in conformance with IEEE C37.111, revision C37.111-1999 or later;

(d) Data files named in conformance with IEEE C37.232, revision C37.232-2011 or later.

**6.1.3.2 Phasor Measurement Unit Requirements**

(1) Phasor measurement unit equipment includes all dynamic disturbance recording equipment with phasor measurement recording capability meeting the requirements in Sections 6.1.3.2.1, Phasor Measurement Unit Recording Requirements, and 6.1.3.2.3, Phasor Measurement Unit Data Recording and Redundancy Requirements.

(2) Phasor measurement unit equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with sub-cycle (+/-2 millisecond) timing accuracy and performance.

***6.1.3.2.1 Phasor Measurement Unit Recording Requirements***

(1) Recorded electrical quantities shall have continuous recording and shall:

(a) Comply with IEEE C37.118.1-2011 or later, IEEE Standard for Synchrophasor format;

(b) Have a minimum output recording rate of 30 samples per second;

(c) Have a minimum input sampling rate of 960 samples per second; and

(d) Be stored locally in accordance with the requirements in Section 6.1.3.2.4, Phasor Measurement Unit Data Retention and Data Reporting Requirements*.*

***6.1.3.2.2 Phasor Measurement Unit Location Requirements***

(1) Each Transmission Facility owner(s) or Generation Facility owner(s) shall, as applicable, install phasor measurement unit equipment at the following locations:

(a) Flexible AC transmission system devices configured to actively control steady-state voltage or power transfer capability operated at or above 100 kV and energized after July 1, 2015;

(b) A Transmission Facility deemed necessary for each published generic transmission constraint within two years of receiving written notice from ERCOT;

(c) New Generation Resources or ESRs over 20 MVA aggregated at a single site and connected to a Transmission Facility at or above 60 kV and placed into service after January 1, 2017;

(d) Existing Generation Resources or ESRs over 20 MVA aggregated at a single site and connected to a Transmission Facility at or above 60 kV following any modification described in paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, with the modification’s Initial Synchronization after January 1, 2022;

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| ***[NOGRR177: Insert item (e) below upon system implementation of NPRR857 and renumber accordingly:]***  (e) New Direct Current Ties (DC Ties) placed into service after January 1, 2019; |

(e) For any Generation Resource or ESR that has not installed phasor measurement units and experiences an unexpected trip or significant reduction in output in response to a system disturbance for which it is unable to determine the cause, ERCOT may require installation of a phasor measurement unit consistent with the requirements of Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment. The Generation Resource or ESR owner shall install the phasor measurement unit at a location specified by ERCOT as soon as practicable but no longer than two years after the date that ERCOT notifies the Entity it must install the equipment.

(f) Each Transmission Element considered part of a monitored IROL interface within two years of notification by ERCOT;

(g) Synchronous condensers supporting the transmission system installed after June 1, 2024.

(h) A Transmission Element within:

(i) A voltage sensitive area consisting of an area with an active UVLS program;

(ii) An area of the ERCOT System with 3,000 MW of ERCOT’s historical simultaneous peak Demand; and

(iii) An area with greater than 1,000 MW of Generation Resources and ESRs with a stability risk identified by ERCOT.

(iv) An area identified in items (i) through (iii) above shall have its equipment installed within two years of the date on which ERCOT informs the owner of the need to install the equipment.

(i) For locations that have experienced an abnormal trip or immediate Load change greater than or equal to 20 MW (including if caused by a DGR, DESR, or SODG) after a fault:

1. ERCOT may require installation of phasor measurement recording equipment;
2. The interconnecting Transmission Service Provider (TSP) or Distribution Service Provider (DSP) shall ensure the recording equipment is installed;
3. A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;
4. The recording equipment will be installed as soon as practicable, but no longer than two years after ERCOT notifies the TSP or DSP of the need to install the equipment, unless the requestor provides an extension;
5. If the TSP or DSP determines it cannot install the recording equipment due to engineering, technical or operational constraints, it will provide to ERCOT, in writing, supporting data or documents.

(j) Any Load consisting of one or more Facilities at a single site with an aggregate peak Demand greater than or equal to 75 MW behind one or more Service Delivery Points if ERCOT requires phasor measurement recording equipment. If required:

(i) The interconnecting TSP or DSP shall ensure the recording equipment is installed;

(ii) A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;

(iii) The recording equipment will be installed as soon as practicable, but no longer than two years after ERCOT notifies the TSP or DSP of the need to install the equipment, unless ERCOT grants an extension;

(iv) If the TSP or DSP determines it cannot install the recording equipment due to engineering, technical or operational constraints, it will provide to ERCOT, in writing, supporting data or documents.

(2) Transmission Facility owners and Generation Resource Facility owners shall install applicable new phasor measurement units identified in paragraph (1) above as soon as practicable.

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| ***[NOGRR255: Replace paragraph (2) above with the following no earlier than <Insert Date at least two years after PUCT approval>:]***  (2) Transmission Facility owners and Generation Resource Facility owners shall have at least 50% of applicable new phasor measurement units identified in paragraph (1) above installed. |

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| ***[NOGRR255: Delete paragraph (2) no earlier than <Insert Date at least four years after PUCT approval>.]*** |

6.1.3.2.3 Phasor Measurement Unit Data Recording and Redundancy Requirements

(1) Recorded electrical quantities shall include data to determine the following:

(a) For Transmission Facility owner locations meeting the requirements in Section 6.1.3.2.2, Phasor Measurement Unit Location Requirements:

(i) Time stamp;

(ii) Phase-to-neutral voltage magnitude/angle data for each phase from at least two distinct Transmission Element measurement points;

(iii) Single phase current magnitude/angle data for each phase from at least two distinct Transmission lines; and

(iv) Frequency and rate-of-change-of-frequency (df/dt) data for at least two Transmission Element measurement points.

(b) For Generation Resource or ESR locations meeting the requirements in Section 6.1.3.2.2:

(i) Time stamp;

(ii) Phase-to-neutral voltage for each phase on the low or high side of the MPT;

(iii) Each phase current and the residual or neutral current on the low or high side of the MPT;

(iv) Active and reactive power on the low or high side of the MPT;

(v) Frequency and df/dt data for at least one generator-interconnected bus measurement; and

(vi) If applicable, dynamic reactive device input/output such as voltage, current, and frequency.

(c) For Facilities identified by ERCOT in Section 6.1.3.2.2:

(i) Phase-to-neutral voltage, or phase-to-phase voltage magnitude/angle data for each phase from at least one transmission terminal bus measurement point, or other ERCOT approved voltages; and

(ii) Single phase current magnitude/angle data for each phase from each interconnected Load terminal on the high or low side of Load delivery point, or other ERCOT approved currents.

6.1.3.2.4 Phasor Measurement Unit Data Retention and Data Reporting Requirements

(1) Market Participants must maintain data regarding the minimum recorded electrical quantities for at least:

(a) A rolling 20 calendar day period for all data stored locally;

(b) At least three years for event data used for model validation in accordance with NERC Reliability Standards; and

(c) At least three years for event data provided to ERCOT, the NERC Regional Entity, or NERC via written request recorded in the context of an event analysis or review.

(2) Each affected Market Participant shall provide ERCOT, upon request, phasor measurement unit data for the Elements identified in these requirements as follows:

(a) Data must be retrievable for 20 calendar days, including the day the data was recorded;

(b) Data subject to paragraph (2)(a) above within seven calendar days of a request unless the requestor grants an extension;

(c) Data in electronic files formatted in conformance with IEEE C37.111, revision C37.111-1999 or later;

(d) Data files named in conformance with IEEE C37.232, revision C37.232-2011 or later.

6.1.4 Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs)

(1) IBRs include any source of electric power connected to the ERCOT System via a power electronic interface that consists of one or more IBR unit(s) capable of exporting active power from a primary energy source or energy storage system.

(2) All transmission-connected IBR facilities operating at 60 kV with gross aggregated nameplate capacity of 20 MVA at a single site must meet all requirements in this section.

(3) Facility owners shall install new fault recording and sequence of events recording equipment identified in this section as soon as practicable.

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| ***[NOGRR255: Replace paragraph (3) above with the following no earlier than <Insert Date at least two years after PUCT approval>:]***  (3) Facility owners shall have at least 50% of new fault recording equipment, sequence of events recording equipment, and phasor measurement units identified in paragraph (2) above installed. |

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| ***[NOGRR255: Delete paragraph (3) no earlier than <Insert Date at least four years after PUCT approval>.]*** |

6.1.4.1 Fault Recording and Sequence of Events Recording Equipment Requirements

(1) Required fault recording equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT approved alternative, with synchronized device clock accuracy and performance within +/- 100 microseconds of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).

(2) Required sequence of events recording equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with +/- 100 microseconds of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).

*6.1.4.1.1 Sequence of Events Recording Data Requirements*

(1) Generation Resource owners and ESR owners shall have sequence of events data for all positions (open/close) for circuit breakers associated with the MPT(s), collector bus, and shunt static or dynamic reactive device(s).

*6.1.4.1.2 Fault Recording Data and Triggering Requirements*

(1) Generation Resource owners and ESR owners shall have fault recording data to determine the following electrical quantities for each triggered fault recording record:

(a) Generation Resource or ESR level fault recording data:

(i) Time stamp;

(ii) Phase-to-neutral voltage for each phase on the high side of the MPT;

(iii) Each phase current and the residual or neutral current on the high side of the MPT;

(iv) If applicable, active and reactive power on the high side of the MPT;

(v) If applicable, frequency and rate-of-change-of-frequency (df/dt) data for at least one generator-interconnected bus measurement; and

(vi) If applicable, dynamic reactive device input/output such as voltage, current, and frequency.

(vii) Applicable binary status.

(2) If the fault recorder does not directly measure the values in paragraphs (1)(a)(iv) through (1)(a)(vi) above, then phasor measurement unit data is acceptable so long as data of sufficient resolution is available to validate dynamic models, identify protection system actions, and identify the cause of a ride-through failure.

(3) Fault recording equipment shall meet the following requirements for a Generation Resource or ESR as described in paragraph (1) above:

(a) Have either continuous data recording or triggering for at least the following:

(i) High-side of the MPT fault recording triggers and, if applicable, any dynamic reactive device FR triggers:

(A) Neutral (residual) overcurrent of 0.20 per unit (p.u.) or less of rated current transformer secondary current;

(B) Any phase under-voltage between 0.85 p.u. and 0.90 p.u., or

(1) Any phase overcurrent above 1.05 p.u. of the maximum emergency current rating, or

(2) Protective relay tripping for all protection groups;

(C) Any phase over-voltage greater that 1.10 p.u.;

(D) Frequency below 59.5 Hz or above 60.5 Hz;

(E) Frequency rate of change for low frequency of -0.08125 Hz/sec or high frequency of 0.125 Hz/sec;

(b) Minimum recording rate of:

(i) 64 samples per cycle for any Fault recording equipment installed on or replaced after June 1, 2024;

(ii) 16 samples per cycle for any Fault recording equipment installed prior to June 1, 2024; and

(c) A single record or multiple records that include pre-trigger record length of at least two cycles and a total record length of at least 2 seconds for the same trigger point.

6.1.4.3 Phasor Measurement Unit Equipment Requirements

(1) Phasor measurement unit equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with synchronized device clock accuracy and performance within +/- 100 microseconds of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).

(2) Recorded electrical quantities shall have continuous recording and be:

(a) Provided in IEEE C37.118.1-2011 or later, IEEE Standard for Synchrophasor format. However, Generation Resources in commercial operation before January 1, 2017 may provide the data in IEEE C37.118.1-2005 format when technically infeasible for its installed equipment to meet the IEEE C37.118.1-2011 or later format;

(b) A minimum output recording rate of 60 samples per second;

(c) A minimum input sampling rate of 960 samples per second; and

(d) Transmitted to an ERCOT phasor data concentrator via a communication link or stored locally per retention requirements in Section 6.1.4.4, Data Retention and Data Reporting Requirements for Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Equipment*.*

(3) Facility owners shall have phasor monitoring data to determine the following:

(a) Time stamp;

(b) Phase-to-neutral voltage, or phase-to-phase voltage magnitude/angle data for each phase from at least one generator-interconnected bus;

(c) Single phase current magnitude/angle data for each phase on the high or low side of an MPT that represents the flow from one or multiple IBR unit(s) behind the MPT;

(d) Frequency and rate-of-change-of-frequency (df/dt) data for at least one generator-interconnected bus; and

(e) Calculated active and reactive power output on the high or low side of the MPT that represents the flow from one or multiple IBR unit(s) behind the MPT.

6.1.4.4 Data Retention and Data Reporting Requirements for Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Equipment

(1) A Generation Resource owner or ESR owner required to have data regarding electrical quantities shall maintain and retain the data, at a minimum, for:

(a) A rolling 20 calendar day period for all data;

(b) At least three years (from the date the data was recorded) for event data used for model validation in accordance with NERC Reliability Standards; and

(c) At least three years for event data provided to ERCOT, the NERC Regional Entity, or NERC via written request recorded in the context of an event analysis or review.

(2) Each Generation Resource owner and ESR owner shall provide ERCOT, upon request, fault recording, sequence of events recording, and phasor measurement unit data as follows:

(a) Data for 20 calendar days, including the day the data was recorded;

(b) Data subject to paragraph (2)(a) above within seven calendar days of a request unless ERCOT grants an extension;

(c) Sequence of events data in ASCII Comma Separated Value (CSV) format as follows: Date, Time, Local Time Code, Substation, Device, State;

(d) Fault recording and phasor measurement unit data in electronic files formatted in conformance with Institute of Electrical and Electronic Engineers (IEEE) C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later;

(e) Data files named in conformance with IEEE C37.232, revision C37.232-2011 or later; and

(f) If available, fault recording data in electronic files in SEL ASCII event report (.EVE), compressed ASCII (.CEV), Motor Start Report (.MSR) and Sequential Events Recorder record (.SER) format.

6.1.5 Maintenance and Testing Requirements

(1) Each Market Participant with dynamic disturbance recording, phasor measurement recording, fault recording, or sequence of events recording equipment identified by Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment, Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment, and Section 6.1.4, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs), shall maintain and test its equipment as follows:

(a) Calibrate or configure the devices at installation and when records from the equipment indicate a calibration or configuration problem;

(b) To ensure data stored locally is available upon request by verifying data availability and quality at least once every 60 calendar days, or institute an automated notification system to detect when the equipment ceases recording required data or fails to timely refresh the data.

(2) Each Market Participant with dynamic disturbance recording equipment, phasor measurement recording, fault recording, or sequence of events recording equipment identified by Section 6.1.2, Section 6.1.3, and Section 6.1.4 shall, within 90 calendar days of discovering a failure of the required data production, either:

(a) Restore the recording capability, or

(b) Notify and submit to ERCOT a plan and timeline for restoring the equipment recording capabilities.

6.1.6 Equipment Reporting Requirements

(1) Each Market Participant with dynamic disturbance recording, phasor measurement recording, fault recording, or sequence of events recording equipment identified by Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment, Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment, and Section 6.1.4, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs), shall:

(a) Maintain a current database summarizing disturbance monitoring equipment installations that includes installation location, type of equipment, equipment make and model, operational status, and a list of the major equipment monitored; and

(b) Have and maintain a complete list of all monitored points at each Facility and, when requested by ERCOT, the NERC Regional Entity, or NERC, provide the list within 30 days.

6.1.7 Review Process

(1) After December 31, 2025, ERCOT shall review disturbance monitoring equipment locations for adequacy when significant changes are made to the ERCOT System or at least every five calendar years.

(2) Transmission Facility owners shall review fault recording and sequence of events recording equipment locations for compliance at least every five calendar years.

(3) Existing Facility owners identified in the reviews shall have three years from the time of review, or from the time of notification from others, to install the equipment.

**ERCOT Nodal Operating Guides**

**Section 8**

**Attachment M**

**Selecting Buses for Capturing Sequence of Events Recording and Fault Recording Data**

**TBD**

This attachment provides the Transmission Facility owner the methodology to use for selecting bus locations for capturing sequence of events recording and fault recording data.

To identify monitored bulk electric system buses for sequence of events recording and fault recording data, each Transmission Facility owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of bulk electric system buses that it owns, excluding buses or Facilities solely representing Inverter-Based Resources (IBRs), as those locations are addressed outside of the process described in this attachment.

For the purposes of this attachment, a single bulk electric system bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those bulk electric system buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 bulk electric system buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 bulk electric system buses determined in Step 3.

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

Step 6. Reduce the bulk electric system buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

* 1,500 MVA or
* 20 percent of median MVA level determined in Step 5.

Step 7. If there are no bulk electric system buses on the list: the procedure is complete and no fault recording and sequence of events recording data will be required. Proceed to Step 9.

If the list has one or more but less than or equal to 11 bulk electric system buses: fault recording and sequence of events recording data is required at the bulk electric system bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3.

During re-evaluation efforts, if the three-phase short circuit MVA of the newly identified bulk electric system bus is within 15% of the three-phase short circuit MVA of the currently applicable BES bus with sequence of events recording and fault recording data than it is not necessary to change the applicable BES bus. Proceed to Step 9.

If the list has more than 11 bulk electric system buses: fault recording and sequence of events recording data is required on at least the 10 percent of the bulk electric system buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. Fault recording and sequence of events recording data is required at additional bulk electric system buses on the list determined in Step 6. The aggregate of the number of bulk electric system buses determined in Step 7 and this Step will be at least 20 percent of the bulk electric system buses determined in Step 6. The additional bulk electric system buses are selected, at the Transmission Facility owner’s discretion, to provide maximum wide-area coverage for fault recording and sequence of events recording data. The following bulk electric system bus locations are recommended:

* Electrically distant buses or electrically distant from other disturbance monitoring equipment devices.
* Voltage sensitive areas.
* Cohesive load and generation zones.
* Bulk electric system buses with a relatively high number of incident transmission circuits.
* Bulk electric system buses with reactive power devices.
* Major Facilities interconnecting outside the Transmission Owner’s area.

Step 9. The list of monitored bulk electric system buses for fault recording and sequence of events recording data is the aggregate of the bulk electric system buses determined in Steps 7 and 8.