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| NOGRR Number | [255](https://www.ercot.com/mktrules/issues/NOGRR255) | NOGRR Title | High Resolution Data Requirements |
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| **Date** | | December 4, 2023 | |
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| Market Segment | | Investor-Owned Utility (IOU) | |

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| Comments |

AEPSC provides these comments to Nodal Operating Guide Revision Request (NOGRR) 255 following discussions by the System Protection Working Group (SPWG) in August and September 2023 to align with current, draft or pending North American Electric Reliability Corporation (NERC) standards.  For example, AEPSC notes that Section 8, Attachment M, Selecting Buses for Capturing Sequence of Events Recording and Fault Recording Data, requires revision to bring it in line with the recently approved PRC-002-4 version and the upcoming PRC-002-5 version.  AEPSC’s proposed revisions to Attachment M are included in these comments. The NERC Standard Drafting Team for PRC-002 has also put out a first draft of PRC-028 that deals with Inverter-Based Resource (IBR) disturbance monitoring; a second draft is most likely due out in January 2024. Some comments provided herein are attempting to align with the NERC effort; however, it is too soon to be sure what will be approved in the NERC efforts.

AEPSC appreciates the Business Case presented by ERCOT for this NOGRR and understands ERCOT’s desire to move it forward expeditiously. However, AEPSC is unaware that a consensus has been developed about revisions to NOGRR255 by SPWG, Dynamics Working Group (DWG) or the IBR Working Group (IBRWG) and urges further review and analysis by these groups before moving forward with the NOGRR.

Regarding implementation time frames: ERCOT has consistently proposed 18 months in numerous places. The existing Guide uses “18 months” only in paragraph (4)(b) of Section 6.1.3.2, Location Requirements, dealing with dynamic disturbance recording equipment. The existing Guide also states “three years” in Section 6.1.6, Review Process, which is in line with NERC PRC-002-3. PRC-002-4 updated this to be “three calendar years”. The proposed changes to this Guide will most likely require evaluation of all existing required installations to determine compliance. This effort, combined with efforts to bring non-compliant sites into compliance, and install monitoring equipment at installations that are now required to be monitored, should be given appropriate implementation time frames in line with PRC-002-4 and the upcoming PRC-028. These time frames will be at least three calendar years and at most possibly five calendar years. AEP acknowledges that additional modifications to the proposed grey-box language in paragraph (2) of 6.1.2.2, Fault Recording and Sequence of Events Recording Equipment Location Requirements, and paragraph (2) of 6.1.3.2.2, Location Requirements (new), may be necessary to accommodate these time frames.

Regarding ERCOT’s use of the phrase “for the maximum period of time the equipment allows, without affecting performance or reliability”, AEPSC believes the insertion of this phrase, or similar, along with the requirement minimum creates a compliance conundrum for the Facility owners and should be avoided. AEPSC questions how an entity would prove that its equipment is setup to the “maximum it allows” when the duration, sample rate, number of channels and number of records before overwriting occurs all play off each other using the same allotted device memory space.

Since most entities responsible for identifying buses for fault recording/sequence of events recording monitoring, under Section 6.1.2.2 and the Section 8, Attachment M process, may have initially done so in 2016 and then re-evaluated in 2021, AEPSC believes it should be made clear to all that another re-evaluation for those purposes is not required until 2026.

Regarding paragraph (2) of Section 6.1.5, Equipment Reporting Requirements, where ERCOT proposes a 30-day requirement, PRC-002 has consistently held that a 90-day requirement is sufficient. AEPSC believes that a 30-day requirement is an unnecessary burden that will possibly create “busy paperwork” that diverts resources from resolving the identified problems.

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| **Revised Cover Page Language** |

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| Nodal Operating Guide Sections Requiring Revision | 6.1, Disturbance Monitoring Requirements  6.1.1, Introduction  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, Recording Requirements (new)  6.1.3.2.2, Location Requirements (new)  6.1.3.2.3, Data Recording and Redundancy Requirements (new)  6.1.3.2.4, 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 |

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| Revised Proposed Guide Language |

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 other identified 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 facilities that are not Inverter-Based Resource (IBR) facilities.

(2) Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment, and its subsections apply to all facilities that are not Inverter-Based Resource (IBR) facilities.

(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, and dynamic disturbance recording equipment 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 identified status points meeting the associated requirements in this Section.

(3) Required fault recording shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with sub-cycle (+/-2 microsecond) timing accuracy and performance of Coordinated Universal Time (UTC), with or without a local time offset for Central Prevailing Time (CPT).

(4) Required sequence of events recording equipment shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with +/- 2 millisecond timing accuracy and performance 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) Triggering for the following:

(i) Neutral (residual) overcurrent of 0.2 p.u. or less of rated current transformer secondary current;

(ii) Any phase under-voltage below 0.85 p.u. for two cycles or longer; or any phase overcurrent above the equipment’s maximum emergency current rating; or protective relay tripping for all protection groups;

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

(iv) 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.

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 shall 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 or at the remote line terminals of each generating station switchyard.

(d) For any individual Load consisting of one or more Facilities at a single site with an aggregate peak Demand greater than or equal to 20 MW that has experienced an abnormal trip or load reduction (including if caused by a DGR, DESR, or 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 install the recording equipment’

(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 it must install the equipment, unless ERCOT provides an extension;

(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 for consideration.

(e) For any individual 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 common Points of Interconnection (POIs) or 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 install the recording equipment;

(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 it must 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 for consideration.

(2) Facility owners shall install the 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 three calendar 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 five calendar years after PUCT approval> and renumber accordingly:]*** |

(3) For any Generation Resource or ESR that has experienced an abnormal trip or power reduction after a fault, ERCOT may require the installation of fault recording and sequence of events recording equipment and the Resource Facility 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 ERCOT notifies the Facility owner it must install the equipment, unless the requestor provides and extension.

(4) For any identified location requiring fault recording and/or sequence of events recording where the Facility to be monitored (line, transformer, circuit breaker, bus, etc.) is owned by another Entity, and the identifying Facility owner is not recording the required data, then:

(a) The identifying Facility owner shall notify the other Facility owner of the requirement to monitor that Facility within 90 calendar days of finalizing the list of locations to be monitored; and

(b) The notified Facility owner shall have three calendar years from the notification date to install the required monitoring equipment.

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, Fault Recording and Sequence of Events Recording Equipment Location Requirements; 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 point-on-wave fault recording data for each triggered fault recording to determine:

(a) Time stamp;

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

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

(d) Active and reactive power on high side of the MPT;

(e) Frequency and 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) For each requested Load Facility identified by ERCOT, 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;

(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 January 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 January 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 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) By December 31, 2026, all dynamic disturbance recording equipment shall function as a phasor measurement unit and meet requirements in Section 6.1.3.1.2, Location Requirements, or a Facility Owner shall install a separate phasor measurement unit in addition to the dynamic disturbance recording equipment, and the phasor measurement unit shall have identical monitoring capabilities as the dynamic disturbance recording equipment.

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

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

(b) Triggered 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 provide notification to Facility owners, 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 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 an MPT; and

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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); and |

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

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, for:

(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 ERCOT-, NERC Regional Entity-, or NERC-initiated 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, Recording Requirements, and 6.1.3.2.3, 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 (+/-1 microsecond) 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) Be compliant 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) Stored locally in accordance with the requirements in Section 6.1.3.2.4, Data Retention and Data Reporting Requirements*.*

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

(1) Facility owner(s) shall 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 three calendar years of receiving written notice from ERCOT;

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

(d) Existing Generation Resource or ESRs over 20 MVA, connected to a Transmission Facility at or above 60 kV, aggregated at a single site 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 experienced a frequency or voltage ride-through failure, ERCOT may require installation of a phasor measurement unit and transmission of the data to an ERCOT phasor data concentrator via a communication link. 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 three calendar years after ERCOT notifies the Entity it must install the equipment, and shall transmit the data within 60 days of installing required recording equipment.

(f) Each Transmission Element part of a monitored IROL interface, within three calendar years of notification from ERCOT;

(g) For any synchronous condensers used to support the transmission system installed after January 1, 2024.

(h) Within three calendar years of notification from ERCOT, any one Transmission Element within:

(i) A voltage sensitive area as defined by an area with an in-service 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 identified stability risks.

(i) For any individual Load consisting of one or more Facilities at a single site with an aggregate peak demand greater than or equal to 20 MW that experienced abnormal trips or Load reductions (including if caused by a DGR, DESR, or SODG) after a fault:

1. ERCOT may require the installation of phasor measurement recording equipment;
2. The interconnecting Transmission Service Provider (TSP) or Distribution Service Provider (DSP) shall install the recording equipment;
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 three calendar years after ERCOT notifies the TSP or DSP it must install the equipment, unless the requestor provides an extension;
5. 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.

(j) For any individual 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 common Points of Interconnection (POIs) or Service Delivery Points:

1. ERCOT may require the installation of phasor measurement recording equipment;
2. The interconnecting Transmission Service Provider (TSP) or Distribution Service Provider (DSP) shall install the recording equipment;
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 three calendar years after ERCOT notifies the TSP or DSP it must install the equipment, unless the requestor provides an extension;
5. 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 for consideration.

(2) Facility owners shall install the 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 three calendar years after PUCT approval>:]***  (2) Facility owners shall have at least 50% of the 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 five calendar 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, 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 df/dt data for at least two Transmission Element measurement points.

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

(i) Time stamp;

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

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

(iv) Active and reactive power on 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 Load Facilities identified by ERCOT in Section 6.1.3.2.2, Phasor Measurement Unit Location Requirements:

(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) A Market Participant required to have and maintain data regarding the minimum recorded electrical quantities shall maintain and retain that data f at a minimum for:

(a) A rolling 30 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 ERCOT, NERC Regional Entity, or NERC-initiated event analysis 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 30 calendar days, including the day the data was recorded;

(b) Data subject to item (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) Inverter-Based Resources (IBRs) include any source of electric power connected to the ERCOT System via 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. An IBR unit is an individual inverter device or group of multiple inverters connected together at a single point of connection. An IBR unit may be an inverter, converter, wind turbine generator, or HVDC converter.

(2) All transmission connected IBR facilities at 60 kV and above with gross aggregated nameplate capacity of 20 MVA or above at a single site are subject to all requirements in this section.

(3) Facility owners shall install the 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 three calendar years after PUCT approval>:]***  (2) Facility owners shall have at least 50% of the new phasor measurement units identified in paragraph (1) above installed. |

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| ***[NOGRR255: Delete paragraph (3) no earlier than <Insert Date at least five calendar 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 sub-cycle (+/-1 microsecond) timing accuracy and performance 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:

(a) All circuit breaker positions;

(b) For at least one IBR unit connected to the last 10% of each collector feeder length. IBR units installed prior to the effective date of this standard and are not capable of recording some of this data are excluded from providing that specific data:

(i) All fault codes;

(ii) All Fault alarms;

(iii) Change of operating mode;

(iv) High and low voltage ride-through mode status;

(v) High and low voltage frequency ride-through mode status; and

(vi) Control system command values, reference values, and feedback signals.

*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 high side of the MPT;

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

(iv) Active and reactive power on 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.

(vii) Applicable binary status.

(b) Individual IBR unit fault recording data from at least one IBR unit connected to any feeder as a location within the last 10% of the longest collector feeder length:

(i) Each AC phase-to-neutral or phase-to-phase voltage, as applicable, at IBR unit terminals or on high side of the IBR unit transformer;

(ii) Each AC phase current and the residual or neutral current, as applicable, on IBR unit terminals or on high side of the IBR unit transformer; and

(iii) DC bus current and voltage. IBR units installed prior to the effective date of this standard and are not capable of recording this data are excluded.

(2) Fault recording equipment shall meet the following requirements for both Generation Resource or ESR level and individual IBR unit level as described in paragraph (1) above:

(a) 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 p.u. of 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;

(ii) IBR unit level fault recording triggers:

(A) Any phase under-voltage between 0.85 p.u. and 0.90 p.u.;

(B) Any phase over-voltage greater than 1.10 p.u.;

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

(D) 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 January 1, 2024;

(ii) 16 samples per cycle for any Fault recording equipment installed prior to January 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 sub-cycle (+/-1 microsecond) timing accuracy and performance 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;

(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*.*

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

(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 measurement;

(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 units behind the MPT;

(d) Frequency and df/dt data for at least one generator-interconnected bus measurement; 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 units 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 and maintain 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 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 ERCOT, NERC Regional Entity, or NERC-initiated 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 locations as follows:

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

(b) Data subject to item (2)(a) above within seven calendar days of a request unless the requestor 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, shall maintain and test recording equipment as follows:

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

(b) Maintain phasor measurement recording equipment to ensure data stored locally is available upon request by verifying data availability and quality at least once every 30 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, 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, within 90 calendar days of the discovery of 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 the equipment to have recording capabilities restored.

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 calendar 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.