**ERCOT Nodal Operating Guides**

**Section 6: Disturbance Monitoring and System Protection**

**February 1, 2026**

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# DISTURBANCE MONITORING AND SYSTEM PROTECTION

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, a Generation Resource owner, or an Energy Storage Resource (ESR) 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 TSP or 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 August 1, 2026:]***  (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 August 1, 2028 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, Generation Resource owner, and ESR 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, Generation Resource owner, and ESR 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, Generation Resource owner, and ESR 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, Generation Resource owner, and ESR 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 6.1.3.1.1, Recording and Triggering Requirements, and 6.1.3.1.3, Dynamic Disturbance Recording 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, Dynamic Disturbance Recording Equipment 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 6.1.3.1.1 and 6.1.3.1.3.  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 and ESR(s) 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, Dynamic Disturbance Recording Equipment 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 and ESR 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;

(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 TSP or 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 August 1, 2026:]***  (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 August 1, 2028.]*** |

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) 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.

(2) Resource Entities for IBRs identified in paragraph (1) shall install and configure fault recording, sequence of events recording, and phasor measurement unit equipment as follows:

(a) IBRs with a Resource Commissioning Date prior to July 25, 2024 shall install and configure fault recording, sequence of events recording, and phasor measurement unit equipment no later than August 1, 2028;

(b) IBRs with an original Standard Generation Interconnection Agreement (SGIA) executed on or before July 25, 2024 and a Resource Commissioning Date after July 25, 2024 shall install and configure fault recording, sequence of events recording, and phasor measurement unit equipment within 365 days of the IBR’s Resource Commissioning Date;

(c) IBRs with an original SGIA executed after July 25, 2024 shall install and configure fault recording, sequence of events recording, and phasor measurement unit equipment no later than the IBR’s Resource Commissioning Date.

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 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 IEEE C37.111, IEEE Standard for 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.

6.1.5.1 Geomagnetic Disturbance (GMD) Measurement Data Processes

(1) When specifically requested by ERCOT, TSPs and Resource Entities shall provide a complete list of GMD measurement equipment installed at their facilities within 30 days.

(2) When specifically requested by ERCOT, TSPs and Resource Entities with GMD measurement equipment installed at their facilities shall provide GMD measurement data for events meeting the reporting criteria set forth in the NERC Geomagnetic Disturbance Data System Data Reporting Instructions, within 60 days.

(3) ERCOT may, at the request of TSPs, post GMD measurement data obtained from TSPs, Resource Entities, or publicly available sources to the Market Information System (MIS) Certified Area for TSPs.

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.

6.2 System Protective Relaying

6.2.1 Introduction

(1) The satisfactory operation of the ERCOT System, especially under abnormal conditions, is greatly influenced by protective relay systems. Protective relay systems are defined as the total combination of:

(a) Protective relays which respond to electrical quantities;

(b) Communications systems necessary for correct operation of protective functions;

(c) Voltage and current sensing devices providing inputs to protective relays;

(d) Station DC supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply); and

(e) Control circuitry associated with protective functions through the trip coil of the circuit breakers or other interrupting devices.

(2) Although relaying of tie points between Facility owners is of primary concern to the ERCOT System, internal protective relay systems often directly, or indirectly, affects the adjacent area also. Facility owners are those Entities owning Facilities in the ERCOT System. Facility owners have an obligation to implement relay application, operation, and preventive maintenance criteria that assure the highest practicable reliability and availability of service to the ultimate power consumers of the concerned area and neighboring areas. Protective relay systems of individual Facility owners shall not adversely affect the stability of the ERCOT System. Additional minimum protective relay system requirements are outlined in the North American Electric Reliability Corporation (NERC) Reliability Standards.

6.2.1.1 Applicability

(1) These objectives and design practices shall apply to all new protective relay systems applied at 60 kV and above unless otherwise specified. It is recognized that there may be portions of the existing ERCOT System that do not meet these objectives. It is the responsibility of individual facility owners to assess the protective relay systems at these locations and to make any modifications that they deem necessary. Similar assessment and judgment should be used with respect to protective relay systems existing at the time of revisions to this guide. Special local conditions or considerations may necessitate the use of more stringent design criteria and practices.

6.2.2 Design and Operating Requirements for ERCOT System Facilities

(1) Protective relay systems shall be designed to provide reliability, a combination of dependability and security, so that protective relay systems will perform correctly to remove faulted equipment from the ERCOT System.

(2) For planned ERCOT System conditions, protective relay systems shall be designed not to trip for swings which do not exceed the steady-state stability limit (note that when out-of-step blocking is used in one location, a method of out-of-step tripping should also be considered). Protective relay systems shall not interfere with the operation of the ERCOT System under the procedures identified in the other sections of these Operating Guides.

(3) Any loading limits imposed by the protective relay system shall be documented and followed as an ERCOT System operating constraint.

(4) The thermal capability of all protection system components shall be adequate to withstand the maximum short time and continuous loading conditions to which the associated protected Transmission elements may be subjected, even as a result of Credible Single Contingency conditions.

(5) Applicable Institute of Electrical and Electronic Engineers (IEEE)/American National Standards Institute (ANSI) guidelines shall be considered when applying protective relay systems on the ERCOT System.

(6) The planning and design of generation, transmission and substation configurations shall take into account the protective relay system requirements of dependability, security and simplicity. If configurations are proposed that require protective relay systems that do not conform to these Operating Guides or to accepted IEEE/ANSI practice, then the Facility owners affected shall negotiate a solution.

(7) The design, coordination, and maintainability of all existing protective relay systems shall be reviewed periodically by the Facility owner to ensure that protective relay systems continue to meet ERCOT System requirements. This review shall include the need for redundancy. Documentation of the review shall be maintained and supplied by the Facility owner to ERCOT or NERC on their request within 30 days. This documentation shall be reviewed by ERCOT for verification of implementation.

(8) Upon ERCOT’s request, within 30 days, Generation Entities shall provide ERCOT with the operating characteristics of any generating equipment protective relay systems or controls that may respond to temporary excursions in voltage, frequency, or loading with actions that could lead to tripping of the generator.

(9) Upon ERCOT’s request, within 30 days, Generation Entities shall provide ERCOT with information that describes how generator controls coordinate with the generator’s short-term capabilities and protective relay systems.

(10) Over-excitation limiters, when used, shall be coordinated with the thermal capability of the generator field winding. After allowing temporary field current overload, the limiter shall operate through the automatic AC voltage regulator to reduce field current to the continuous rating. Return to normal AC voltage regulation after current reduction shall be automatic. The over-excitation limiter shall be coordinated with the over-excitation protection so that over-excitation protection only operates for failure of the voltage regulator/limiter. Upon ERCOT’s request, within 30 days, Generation Entities shall provide documentation of coordination.

6.2.3 Performance Analysis Requirements for ERCOT System Facilities

(1) All ERCOT System disturbances (unwanted trips, faults, and protective relay system operations) shall be analyzed by the affected facility owner(s) promptly and any deficiencies shall be investigated and corrected.

(2) All protective relay system misoperations and all associated corrective actions in Generation Resource systems, Energy Storage Resource (ESR) systems, or Transmission Facility systems 100 kV and above shall be documented, and documentation shall be supplied by the affected Facility owner(s) to ERCOT per the timeline established in paragraph (6) below or upon request. Any of the following events constitute a reportable protective relay system misoperation:

(a) Failure to Trip – Any failure of a protective relay system to initiate a trip to the appropriate terminal when a fault is within the intended zone of protection of the device (zone of protection includes both the reach and time characteristics). Lack of targeting, such as when a high-speed pilot system is beat out of high-speed zone is not a reportable misoperation. Furthermore, if the fault clearing is consistent with the time normally expected with proper functioning of at least one protection system, then a primary or backup protection system failure to operate is not required to be reported;

(b) Slow Trip – An operation of a protective relay system for a fault in the intended zone of protection where the relay system initiates tripping slower than the system design intent;

(c) Unnecessary Trip During a Fault – Any unnecessary protective relay system operation for a fault not within the zone of protection. Operation as backup protection for a fault in an adjacent zone that is not cleared within the specified time for the protection for that adjacent zone is not a reportable operation; and

(d) Unnecessary Trip Other Than Fault – Any unnecessary protective relay system operation when no fault or other abnormal condition has occurred. Note that an operation that occurs during on-site maintenance, testing, construction and/or commissioning activities is not a reportable misoperation.

(3) Any of the following events do not constitute a reportable protective relay system misoperation:

(a) Trip Initiated by a Control System – Operations which are initiated by control systems (not by protective relay system), such as those associated with generator controls, or turbine/boiler controls, Static VAr Compensators, Flexible AC Transmission devices, HVDC terminal equipment, circuit breaker mechanism, or other facility control systems, are not considered protective relay system misoperations;

(b) Facility owner authorized personnel action that directly initiates a trip is not considered a misoperation. It is the intent of this reporting process to identify misoperations of the protective relay system as it interrelates with the electrical system, not as it interrelates to personnel involved with the protective relay system. If an individual directly initiates an operation, it is not counted as a misoperation (i.e., unintentional operation during tests); however, if a technician leaves trip test switches or cut-off switches in an inappropriate position and a system fault or condition causes a misoperation, this would be counted as a protective relay system misoperation; and

(c) Failure of Relay Communications – A communication failure in and of itself is not a misoperation if it does not result in misoperation of the associated protective relay system.

(4) All Remedial Action Scheme (RAS) misoperations shall be documented, including corrective actions, and the documentation supplied to ERCOT, the Reliability Monitor, and the NERC Regional Entity, per the timeline established in paragraph (1) of Section 11.2.1, Reporting of RAS Operations. Any of the following events constitute a reportable RAS misoperation:

(a) Failure to Operate – Any failure of a RAS to perform its intended function within the designed time when power system conditions intended to trigger the RAS occur;

(b) Unnecessary Operation – Any operation of a RAS that occurs without the occurrence of the intended system trigger condition(s);

(c) Unintended System Response – A RAS operates for the system conditions it was designed to operate for but the RAS operation results in an unintended adverse power system response;

(d) Failure to Mitigate – A RAS operates for the system conditions it was designed to operate for but fails to mitigate the power system conditions it was designed to address;

(e) Failure to Arm – Any failure of a RAS to automatically arm itself when power system conditions that are intended to arm the RAS occur; and

(f) Failure to Disarm or Reset – Any failure of a RAS to automatically disarm or reset itself when power system conditions that are intended to disarm the RAS occur.

(5) Transmission Facility owners shall document the performance of their protective relay systems. The performance data reported shall include the total number of protective relay system misoperations and the total number of events.

(6) Protective relay system misoperations shall be reported to ERCOT using either the Relay Misoperations Report form on the ERCOT website or any other form that contains the same information and that is provided in a similar format as the ERCOT Relay Misoperations Report. Relay Misoperation Reports shall be submitted to ERCOT at [shiftsupv@ercot.com](mailto:shiftsupv@ercot.com) on a quarterly basis per the following schedule:

|  |  |
| --- | --- |
| **Data submission** | **Date\*** |
| Submission of the 1st Quarter data | May 31 |
| Submission of the 2nd Quarter data | August 31 |
| Submission of the 3rd Quarter data | November 30 |
| Submission of 4th Quarter data | February 28 |
| *\*Next Business Day if date specified is a non-Business Day* | |

(7) All Facility owners shall install, maintain, and operate disturbance monitoring equipment in accordance with the requirements in Section 6.1.2.3, Fault Recording and Sequence of Events Recording Data.

6.2.4 Protective Relay System Failure Response

(1) A bulk electric system element can no longer perform as designed if there is a failure of its protective relay systems such as the inability to maintain a critical clearing time or the inability to maintain selectivity. The inability to maintain a critical clearing time is a failure to trip or a slow trip. The inability to maintain selectivity is an unnecessary trip during a fault or an unnecessary trip other than a fault. It is not considered a protection failure if additional protection systems are available to operate as previously stated above.

(2) Protective relay systems include: relays, associated communication systems, voltage and current sensing devices, station batteries, and DC control circuitry.

(3) The owner of protective relay systems will immediately notify the appropriate Qualified Scheduling Entity (QSE) and Transmission Operator (TO) via phone call, when the owner has determined that the protective relay system has failed.

(4) The affected QSE or TO shall immediately notify the ERCOT Shift Supervisor via phone call and initiate prompt corrective action. These corrective actions are to address reliability issues for the systems that the QSE and TO monitor and/or operate.

(5) Corrective action in this context means limiting exposure to the bulk electric system and does not include the maintenance or repair of relays. These actions shall be taken as prescribed by the Outage Coordination process in Section 2.4, Outage Coordination, and Protocol Section 3, Management Activities for the ERCOT System. Examples of corrective actions include:

(a) Removing the affected facility from service, and

(b) Entering the status change into Outage Scheduler.

(6) ERCOT shall determine the impact on the ERCOT System and direct the necessary corrective actions (typically reconfiguration and/or re-dispatch) to address any reliability issues. Examples of corrective actions include:

(a) Re-dispatching or requesting of re-dispatching as studies dictate;

(b) Possible reconfiguration of the ERCOT System; or

(c) Firm Load shed.

(7) The affected QSE and TO shall promptly notify the ERCOT Shift Supervisor via phone call of the return to service of the previously identified protective relay systems.

6.2.5 Maintenance and Testing Requirements for ERCOT System Facilities

(1) The facility owner shall test and verify the proper operation of each new or modified protective relay system and associated communications channels prior to placing the equipment in its zone(s) of protection in service. For protective relay systems that utilize a propagation-delay-sensitive operating principle and a communication channel with potentially significant propagation delay, time-synchronized “end-to-end” testing of the protective relay system shall be performed to verify that communication channel performance (including alternate routes) is adequate for proper operation.

(2) Facility owners shall have documented protective relay system maintenance and testing programs in place. Documentation shall include identification of protective relay system, a summary of testing procedures including requirements for frequency of tests, and the date last tested.

(3) The facility owner shall periodically test and inspect all components of the protective relay system to assure continued reliability. Identified deficiencies shall be corrected. Documentation demonstrating compliance with the facility owner’s maintenance and testing programs shall be supplied to ERCOT or NERC upon their request within 30 days.

6.2.6 Requirements and Recommendations for ERCOT System Facilities

6.2.6.1 General Protection Criteria

6.2.6.1.1 Dependability

(1) Except as noted in paragraphs (4) and (5) below, all elements of the ERCOT System operated at 100 kV and above (i.e., lines, buses, transformers, generators, breakers, capacitor banks, etc.) shall be protected by two protective relay systems. Each protective relay system shall be independently capable of detecting and isolating all faults thereon.

(2) The protective relay system design should avoid the use of components common to the two protective relay systems. Areas of common exposure should be kept to a minimum to reduce the possibility of both protective relay systems being disabled by a single contingency.

(3) The use of two identical protective relay systems is not generally recommended, due to the risk of simultaneous failure of both protective relay systems because of design deficiencies or equipment problems.

(4) Breaker failure protection should be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault. This protection need not be duplicated.

(5) On installations where freestanding or column-type current transformers are provided on one side of the breaker only, the protective relay systems should be provided to detect a fault on the primaries of such current transformers. This protection need not be duplicated. Application of freestanding current transformers requires extra care to ensure that the relaying is proper and that the schemes overlap.

6.2.6.1.2 Security

(1) The protective relay systems should be designed to isolate only the faulted element, except in those circumstances where additional elements should be tripped intentionally to preserve system integrity. For faults external to the protected zone, each protective relay systems should be designed to either not operate, or to operate selectively with other systems, including breaker failure. In this context, the limits of the protected zone are defined by the circuit breakers.

6.2.6.1.3 Dependability and Security

(1) The protective relay systems should be no more complex than required for any given application.

(2) To the maximum degree practicable, the components used in the protective relay systems should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions, to ensure that the reliability of the protective relay system(s) is not degraded by the components.

(3) The protective relay system shall be designed to minimize the possibility of component failure or malfunction due to electrical transients and electromagnetic interference or external effects such as vibration, shock and temperature.

(4) Critical features associated with protective relay systems and circuit breaker operation shall be annunciated or monitored.

(5) The protective relay system circuitry and physical arrangements shall be carefully designed so as to minimize the possibility of incorrect operations due to personnel error.

(6) Computerized fault studies shall be used during the planning or design stages to analyze the effects of an addition or modification to the ERCOT System and to determine proper protective relay system coordination.

(7) To the extent dynamic or transient analysis shows that a protection system, designed within the guidelines contained in these Operating Guides, is unable to operate in a manner that maintains continuity of service and/or system stability in accordance with NERC Reliability Standards and the Operating Guides, additional measures shall be considered for improvement to the operation of the protection system. Additional measures may include redundant current transformers, voltage transformers, power supplies and communication paths.

6.2.6.1.4 Operating Time

(1) The objective of the protective relay systems is to take corrective action in the shortest practical time with due regard to selectivity, dependability and security. In cases where clearing times are deliberately extended, consideration should be given to the following:

(a) Effect on ERCOT System stability or reduction of stability margins.

(b) Possibility of causing or increasing damage to equipment and subsequent extended repair and/or outage time.

(c) Effect of disturbances on service to customers and neighboring facility owners.

6.2.6.1.5 Testing and Maintenance

(1) The design of protective relay systems both in terms of circuitry and physical arrangement shall facilitate periodic testing and maintenance. Test devices or switches should be provided to eliminate the necessity for removing or disconnecting wires during periodic testing. Protective relays for transmission lines shall be designed to support periodic testing and maintenance while the transmission line remains in service.

(2) Commissioning of new equipment should consist of the following steps:

(a) Relay installation wiring diagrams cross-checked against schematics;

(b) After completion of construction, physical check of wiring and relay installation;

(c) Check and testing before energizing of all equipment in the zone of protection, including relay testing. It is desirable to test the relays at the setting the relay will have in service;

(d) Check of supporting paperwork, such as relay test reports;

(e) Check that relays physically agree with the relay settings;

(f) Check that proper settings have been made;

(g) Written record of trip check and energize procedure;

(h) In-service measurement of voltage and current magnitudes and phase angles, and comparison to expected values and to other instrumentation; and

(i) Release to facility owner’s operating personnel for service.

6.2.6.1.6 Analysis of System Performance and Associated Protection Systems

(1) Relay operation and settings shall be reviewed periodically and whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.

(2) Naturally occurring faults and other system disturbances should be analyzed as a source of information as to the health of relay schemes in the facility owner’s system and the ERCOT System. Sources of information usually available are:

(a) Short circuit study for the exact conditions of the fault;

(b) Fault recorder traces;

(c) Sequence of events data recording the opening and closing of contacts in the protective relay scheme and associated communication equipment;

(d) Fault locator data;

(e) SCADA logger output of breaker operation and alarms;

(f) Interviews with operating personnel and/or other witnesses;

(g) Field report of relay flags and breaker counter changes;

(h) Field report of the fault location, if found;

(i) Records of relay setting, relay testing, trip check and energize procedures as carried out, in-service measurements, relay wiring diagrams and schematics, manufacturers' information;

(j) Other utility personnel and System Protection Working Group (SPWG) members; and

(k) Manufacturers' application and design engineers.

(3) Steps that may be followed in analyzing a disturbance include:

(a) Gather data;

(b) Create a time line consisting of events and periods between events;

(c) Compare actual and calculated values of current and voltage during the periods between events;

(d) Compare actual and expected breaker operations and flags;

(e) Choose the least complicated explanation for contradictory information and to fill in missing information;

(f) Gather additional information as indicated to prove or disprove explanations;

(g) Iterate;

(h) Document by issuing a report of all findings, changes, and recommendations; and

(i) After a reasonable time, check back to see if the recommendations have been carried out.

6.2.6.2 Equipment and Design Considerations

6.2.6.2.1 Current Transformers

(1) Current transformers associated with protective relay systems shall have adequate steady state and transient characteristics for their intended function.

(2) The output of each current transformer shall remain within acceptable limits for the connected burdens under all anticipated fault currents to ensure correct operation of the protective relay system.

(3) Current transformers or their secondary windings shall be located so that adjacent protection zones overlap.

(4) Current transformer secondary wiring shall be grounded at only one point. When multiple current transformers are interconnected, the combination shall have only one ground.

(5) For all newly installed protective relay systems, the two protective relay systems protecting a zone shall utilize isolated and separate current transformers, or isolated and separate secondary windings in the case of free-standing current transformers.

(6) Other considerations include:

(a) Internal bushing current transformers are preferred over external slip-over current transformers;

(b) 10L800 (C800) class current transformers are preferred for relaying;

(c) Breakers and free-standing current transformers with four or more sets of current transformers are preferred;

(d) Over-the-bushing external current transformers can sometimes solve problems when there aren't enough current transformers. Note that there may be an unprotected region between the external current transformer and the bushing current transformer; and

(e) Shorting type terminal blocks should be provided for all current transformers.

6.2.6.2.2 Voltage Transformers and Potential Devices

(1) Voltage transformers and potential devices associated with protective relay systems shall have adequate steady state and transient characteristics for their intended functions.

(2) Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their relay accuracy over their specified primary voltage range.

(3) Usually one set of voltage transformers and /or potential devices with two separate secondary windings per voltage transformer per bus (i.e., single bus substation configuration) or per power system element (i.e., ring bus and breaker-and-a-half substation configurations) is sufficient. For existing systems, the two protective relay systems may use separate secondary windings or one of the secondary windings may be dedicated to supplying the polarizing potential and the other winding used to supply other protection and monitoring functions. For all new installations, if the two protective relay systems protecting a zone each require a voltage transformer or potential device input for protection functions, they shall utilize isolated and separate secondary windings unless ERCOT determines that one of the secondary windings must be dedicated to metering applications.

(4) Voltage transformer and potential device secondary wiring shall be grounded at only one point. ANSI/IEEE C57 recommends grounding at the panel.

(5) Voltage transformer installations shall be designed with due regard to ferroresonance due to capacitance across the interrupter at 138 kV and above.

(6) Other considerations include:

(a) Special attention should be given to the physical properties of secondary circuit fuses;

(b) Voltage transformers and potential devices should be suitable for relaying and SCADA telemetry; and

(c) Loss of protective system voltage such as a fuse failure should be provided as SCADA alarm input.

6.2.6.2.3 Batteries and Direct Current Supply

(1) DC batteries associated with protective relay systems shall have a high degree of reliability.

(2) Two batteries each with its own charger should be provided at each location. An acceptable alternative is one battery with two separately protected branches. The two protective relay systems protecting a zone shall be supplied from the separate batteries or branches. For transmission facilities at 100 kV and above, two batteries shall be required in locations that remote backup clearing of lines and substation faults is not achieved. For new upgraded transmission facilities at 200 kV and above with two or more transmission voltage breakers, two batteries each with its own charger, are required.

(3) Each battery shall have sufficient capacity to permit operation of the station, in the event of a loss of its battery charger or the AC supply source, for the period of time necessary to transfer the load to the other battery or to re-establish the supply source. Each battery and its associated charger shall have sufficient capacity to supply its share of the DC Load of the station.

(4) A fault at the battery terminals can only be interrupted by a mid-bank protective device. If a mid-bank protective device is not used, then the connections between the battery terminals and the main protective devices shall possess the highest possible degree of reliability.

(5) Battery chargers and all associated circuits shall be protected against short circuits. All protective devices shall be coordinated to minimize the number of DC circuits interrupted.

(6) The regulation of DC voltage shall be designed such that, under all possible loading conditions, voltage within acceptable limits will be supplied to all devices.

(7) DC systems shall be monitored to detect abnormal voltage levels, both high and low, DC grounds, and loss of AC to the battery chargers. Loss of DC to relay schemes shall be alarmed. Also, where possible the loss of AC to the battery chargers and loss of DC should be provided as SCADA alarm inputs.

(8) DC systems shall be designed to minimize AC ripple and voltage transients.

(9) The DC circuit protective devices used shall have published DC interrupting ratings suitable for the required circuit duty.

6.2.6.2.4 AC Auxiliary Power

(1) There should be two sources of station service AC supply, each capable of carrying all the critical loads associated with protective relay systems.

(2) Failure of station service AC supply should be alarmed over SCADA.

6.2.6.2.5 Circuit Breakers

(1) Two trip coils, one associated with each protection system, shall be provided for each operating mechanism. The failure of one coil shall not damage or impair the operation of the other coil.

(2) The design shall be such that the breaker will operate if either both trip coils are energized simultaneously, or either trip coil alone, and verified by tests.

(3) Circuit breaker auxiliary switches used in protection systems should be highly reliable with a positive make-break action and good contact wipe. Multiplier contacts simulating breaker auxiliary switches should be used with caution in protection systems.

(4) A three-phase and line-to-ground interrupting study to validate or indicate breaker interrupting rating shall be performed.

6.2.6.2.6 Communications Channels

(1) Where communication channels are required for the protective relay system purposes, the communication facilities shall have a degree of reliability no less than that of the other protective relay system components. For extra security, the output contacts from two independent channels may be wired in series.

(2) Where communication channels are required in each of the two protective relay systems, the channels shall be separated physically and designed to minimize the risk of both channels being disabled simultaneously by a single contingency.

(3) Communication channels shall be provided with means to verify signal performance.

(4) Other considerations include:

(a) Report loss of channel over SCADA;

(b) Automatic testing of power line carrier is desirable to reduce false trips from failure to block; and

(c) Split up power line carrier Loads between DC sources so that loss of one fuse does not disable all the carrier sets. If all the carrier sets were to be disabled, then multiple false trips during a fault could result.

(e) See also Section 8.3.4, TDSP and QSE Supplied Communications.

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| ***[NOGRR177: Replace paragraph (e) above with the following upon system implementation of NPRR857:]***  (e) See also Section 7.1.2, WAN Participant Responsibilities. |

6.2.6.2.7 Control Cables and Wiring

(1) Control cables, wiring and auxiliary control devices should be such as to assure high reliability with due consideration to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

(2) Other considerations include:

(a) AC or DC go-and-return functions should be implemented in the same cable to avoid induction loops;

(b) Individual wires in cables should have colored jackets, not black jackets with a "color" printed on the jacket;

(c) Standardization of the relationship between wire colors and functions is desirable;

(d) No splice in any wire or cable;

(e) All cables terminated on terminal blocks; and

(f) Shielded cable should be installed in locations where electric fields, magnetic fields, or electromagnetic interference is sufficient to disrupt the reliable operation of the control cable and it cannot be mitigated by other means.

6.2.6.2.8 Environment

(1) Means shall be employed to maintain environmental conditions that are favorable to the correct performance of protective relay systems. Particular attention should be given to solid-state equipment installations.

(2) Other potential hazards detrimental to installations include:

(a) Fire ants;

(b) Snakes;

(c) Trash and leftover hardware;

(d) Gunfire;

(e) Hand-held radio keyed near solid-state relays;

(f) Severe cold weather conditions possibly impacting operation of circuit breakers, DC battery;

(g) Rats;

(h) Dust, dirt, grime;

(i) Water;

(j) Theft of substation and transmission grounds; and

(k) Batteries located in same room as relays.

6.2.6.3 Specific Application Considerations

6.2.6.3.1 Transmission Line Protection

(1) Each of the two independent protective relay systems shall detect and initiate action to clear any line fault without undue system disturbance. Protective relay systems shall operate for line faults so that, if ultimate clearing should be accomplished by a breaker failure scheme, a widespread disturbance will not result. A protective relay system, which can operate for faults beyond the zone it is designed to protect, shall be selective in time with other protective relay systems, including breaker failure.

(2) For newly installed transmission line protective relay systems:

(a) Fuses shall not be used in the 3Vo polarizing supply for ground relays.

(b) Loss-of-potential function shall be used for schemes dependent on voltage for correct operations. SCADA alarms shall be provided for loss-of-potential conditions.

(c) Dual communication-aided protection over dual communications channels shall be used where dynamic and/or voltage stability studies indicate non-pilot protection operating times are inadequate.

(3) Transmission line protection should include:

(a) One independent protective relay system of phase and ground protection over a communications channel;

(b) A secondary independent protective relay system of at least two zones of phase protection and at least two zones of ground protection, or ground directional overcurrent relaying (time delay and instantaneous);

(c) “Ground chain protection” or switch-to-on-fault to recognize and trip for a three-phase fault right at the terminals, in service for a short period of time just as the line is energized, for lines with line side voltage transformers and protection elements dependent on distance measurement;

(d) Recognition and trip for open conductor is desirable but not required;

(e) Overload protection is provided by SCADA analog alarms and dispatcher discretion;

(f) Fault detector relays to supervise phase distance relaying to prevent inadvertent trip due to voltage transformer failure;

(g) Short lines may require special attention, such as dual primary schemes, etc;

(h) For transmission facilities with series compensation, dual communication-aided protection should be used. At least one of the two protective relay systems should be differential type; and

(i) For any transmission line that has dual communication-aided protection systems, at least one of the two protective relay schemes should be of a differential type in any location where an adequate communications infrastructure exists or is planned and there are no mitigating circumstances (e.g. tapped loads).

6.2.6.3.2 Transmission Station Protection

(1) Each zone in a station shall be protected by two independent protective relay systems. For zones not protected by line protection, at least one of the two protective relay systems shall be a differential type.

(2) Protective relay systems shall be designed to operate for station faults so that, if ultimate clearing is accomplished by a breaker failure scheme, a widespread disturbance will not result. Protective relay systems shall be designed to operate properly for the anticipated range of currents.

(3) Station protection should consist of:

(a) Bus differential or bus overcurrent protection of all buses;

(b) All transformers protected by transformer differential, transformer overcurrent, or fuses (for small transformers). Note that ferroresonance is possible for fused transformers above 69 kV; and

(c) Sudden pressure relay protection for transformer main tanks and transformer tap changer compartments.

(d) For transformers with conservator tanks, gas accumulator relay (also known as a Buchholz relay) protection for the transformer main tanks and transformer tap changer compartments are preferred in addition to sudden pressure relay protection.

6.2.6.3.3 Breaker Failure Protection

(1) Breaker failure protection should be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault.

(2) The breaker failure protection should be initiated by each of the protection systems that trip that breaker. It is not necessary to duplicate the breaker failure protection itself.

(3) Induction cup, solid state, or microprocessor based current detectors shall be used to determine if a breaker has failed to interrupt.

(4) Plunger or clapper type overcurrent relays are not recommended as breaker failure fault detectors.

(5) For all newly installed or upgraded relay systems, a cross-tripping means such that each protective relay system can operate both circuit breaker trip coils without compromising the separation of the DC supplies is recommended.

(6) Breaker failure schemes shall be designed such that if fault clearing should be accomplished through operation of the breaker failure scheme, an uncontrolled separation and collapse of the ERCOT System will not result. Breaker failure schemes shall be designed to be selective in time with other protective relay systems and/or particular system requirements.

6.2.6.3.4 Generator and Energy Storage Resource Protection and Relay Requirements

(1) Generator or Energy Storage Resource (ESR) faults shall be detected by more than one protective relay system. These may include faults in the unit or unit leads, unit transformer, and unit-connected station service transformer.

(2) Generators and ESRs shall be protected to keep damage to the equipment and subsequent outage time to a minimum. In view of the special consideration of generator unit protection, the following are some of the conditions that should be detected by the protection systems:

(a) Unbalanced phase currents;

(b) Loss of excitation;

(c) Over-excitation;

(d) Field ground;

(e) Inadvertent energization or reverse power;

(f) Uncleared system faults; and

(g) Off-frequency.

It is recognized that the overall protection of a generator will also involve non-electrical considerations. These have not been included as part of this criteria.

(3) The apparatus shall be protected when the generator is starting up or shutting down as well as running at normal speed; this may require additional relays, as the normal relays may not function satisfactorily at low frequencies.

(4) A generator or ESR shall not be tripped for a system swing condition except when that particular generator is out of step with the remainder of the system. This does not apply to protective relay systems designed to trip the generator as part of an overall plan to maintain stability of the ERCOT System.

(5) The loss of excitation relay shall be set with due regard to the performance of the excitation system.

(6) In the case of a generator or ESR bus fault or a primary transmission system relay failure, the generator protective relaying may clear the generator independent of the operation of any transmission protective relaying.

(7) If requested by ERCOT, within 30 days of ERCOT’s request, Generation Resources or ESRs shall provide ERCOT with the operating characteristics of any generating unit’s or ESR’s equipment protective relay systems or controls that may respond to temporary excursions in voltage with actions that could lead to tripping of the generating unit or ESR.

6.2.6.3.5 Automatic Under-Frequency Load Shedding Protection Systems

(1) Automatic Under-Frequency Load Shedding (UFLS) systems are classified as protective relay systems. The maintenance requirements, discussed in Section 6.2.5, Maintenance and Testing Requirements for ERCOT System Facilities, apply to UFLS protection systems as well.

(2) Automatic UFLS systems are generally located on equipment operated below 60 kV; however, they have a direct effect on the operation of the ERCOT System during major emergencies.

(3) The criteria for the operation of these protection systems are detailed in Section 2.6, Requirements for Under-Frequency and Over-Frequency Relaying.

(4) Automatic UFLS protection systems need not be duplicated.

(5) Generator and turbine under-frequency protection systems shall be coordinated with Section 2.6.

(6) On pressurized water reactor steam supply units where under-frequency related protection systems are installed to detect loss of coolant flow condition, these protection systems shall be coordinated with the automatic UFLS program.

(7) Automatic Load restoration for an under-frequency Load shedding operation is not currently utilized in ERCOT.

6.2.6.3.6 Automatic Under-Voltage Load Shedding Protection Systems

(1) Automatic Under-Voltage Load Shedding (UVLS) systems are classified as protective relay systems. The maintenance requirements, discussed in Section 6.2.5, Maintenance and Testing Requirements for ERCOT System Facilities, apply to UVLS protection systems as well.

(2) The requirement for under-voltage relaying shall be determined by system studies performed/administered by ERCOT designated working groups or equipment owners. The system studies should indicate the following:

(a) Amount of Load to be shed to restore voltage to minimum acceptable level or higher;

(b) The minimum and maximum time delay allowed before automatically shedding Load;

(c) The voltage level(s) at which to initiate automatic relay operation; and

(d) The location(s) for effectively applying UVLS protection systems.

(3) Automatic UVLS protection systems need not be duplicated.

(4) Analyses shall be performed on UVLS schemes by working groups and/or equipment owners as assigned by ERCOT to demonstrate that they are expected to act before generators trip Off-Line due to the protective relay requirements, as specified in paragraph (4)(a) of Section 2.9, Voltage Ride-Through Requirements for Generation Resources and Energy Storage Resources. A specific exemption from this analysis requirement may be provided by the ROS.

(5) Under-voltage protection systems shall be designed to coordinate with other protective devices and control schemes during momentary voltage dips, sustained faults, low voltages caused by stalled motors, motor starting, etc.

(6) Automatic Load restoration for an UVLS operation is not currently utilized in ERCOT.

(7) The UVLS scheme shall be designed to ensure reliable operation. The scheme shall not impede continued operation of any Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) during a UVLS event, except as permitted by Protocol Section 3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs).

(8) In addition, protective relaying for Generation Resources and ESRs must be designed to meet voltage ride-through criteria as detailed in Section 2.9.

(9) Restoration of any Load shed by UVLS shall be coordinated with ERCOT.