ERCOT Settlement Metering Operating Guide

June 1, 2025

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Section 1: EPS Metering Facility Requirements

March 1, 2021

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1 EPS METERING FACILITY REQUIREMENTS

1.1 Purpose and Scope

(1) The purpose of these guidelines is to outline standards, specifications, procedures and practices for ERCOT-Polled Settlement (EPS) Metering Facilities.

(2) The scope of these guidelines is limited to EPS Metering and to the equipment and practices necessary to provide accurate metering of electrical quantities for settlement.

(3) These guidelines are intended to apply to EPS Metering Facilities. These guidelines are not applicable to measurements intended for local monitoring or for station relaying, control, and operation. Refer to the appropriate section of the Protocols and Operating Guides for requirements of other metering applications.

1.2 General

(1) Measurements covered under this guideline include energy quantities used for settlement metering as referenced in the Protocols and this Settlement Metering Operating Guide (SMOG).

(2) All devices used in ERCOT-Polled Settlement (EPS) Metering shall conform to or exceed standards outlined in the Protocols and this SMOG.

(3) Test switches shall be installed in the instrument transformer secondary circuits to provide a means to measure quantities required to certify the facility and allow the application of test quantities to the meter. Test switches should be utilized for all devices in the metering circuit. Test switches shall conform to the latest revision of American National Standards Institute (ANSI) C12.9, American National Standard For Test Switches for Transformer-Rated Meters, applicable at time of original installation.

1.3 Current Transformers

1.3.1 Fault Withstand

(1) Current transformers shall be capable of withstanding available fault current levels.

1.3.2 Quantity

(1) Current transformers shall be installed, one in each phase, for metering of an ERCOT-Polled Settlement (EPS) Metering Facility, which is connected to a four-wire wye neutral grounded system or in two phases for metering of an EPS Metering Facility, which is connected to a three-wire ungrounded system.

(2) Current transformers may be installed in two phases for metering of an EPS Metering Facility which is connected to a three-wire wye, neutral grounded transmission system if phase-to-ground loads or phase-to-ground sources are not connected between the metering point and the power transformer primary windings.

(a) The EPS Metering Facility may have power equipment connected that does not provide a path for ground current (e.g. three phase power transformers with delta or ungrounded wye winding connection, phase-to-phase connected single phase power transformers, etc.). Exclusions are:

(i) Potential transformers; and/or

(ii) Surge protectors.

(b) The Transmission and/or Distribution Service Provider (TDSP) shall verify that all power transformer primary connections behind the metering point are ungrounded delta, ungrounded wye or phase to phase. This verification shall be performed by the TDSP on an annual basis, at each required site certification and any time changes are made to the circuit configuration.

(c) The EPS Metering Design Proposal one-line drawing will need to include designation of all connected power transformers.

(i) One-line detail must show all tapped power transformers.

(ii) When new power transformers are tapped, a new design proposal must be submitted to ERCOT showing the additional tapped power transformer.

(d) A professional engineer registered in the State of Texas shall provide a certification that the three voltage transformer - two current transformer metering is an accurate metering configuration for the specific EPS metering point as specified in this document. Such certification should be based on the TDSP detailed drawings submitted with the site approval request, with confirmation of site certification by an approved TDSP EPS Meter Inspector.

(e) TDSP shall be responsible for confirming that the facility meets the requirements outlined above. For metering an EPS Metering Facility connected to a three-wire wye neutral grounded transmission system and not meeting these requirements, current transformers shall be installed in each phase.

(3) Current transformers may be installed in two phases for metering of an EPS Metering Facility which is connected to a three-wire wye, high or low impedance grounded distribution system, if phase to ground loads or phase to ground sources are not connected behind the metering point and the high or low impedance ground is installed as part of a fault monitoring system for the facility.

(a) The TDSP shall verify the existence of the high or low impedance ground and the existence of the fault monitoring system during initial site certification and at least every three years thereafter. Such verification shall be documented on either the EPS Metering Test Report or the EPS Metering Site Certification Form.

(b) The Resource Entity shall provide written certification, sealed by a professional engineer registered in the State of Texas, that all power transformer primary connections behind the EPS metering point are ungrounded delta, ungrounded wye or phase to phase and that the system configuration, as connected behind the EPS metering point, will not support a phase to ground load connection. Such certification shall be submitted with the EPS Metering Design Proposal.

(c) For metering an EPS Metering Facility connected to a three-wire wye, high or low impedance grounded distribution system and not meeting these requirements, current transformers shall be installed in each phase.

1.3.3 Burden

(1) The current transformer burdens shall be kept as small as practical and shall not exceed the burden rating of the current transformer.

(2) During annual testing, the total current transformer burden shall be checked by the addition of a known burden to determine that the specified burden capability of the current transformer is not exceeded. ERCOT may waive the requirement for the burden check, upon receipt of written information from the TDSP that provides the specific reason(s) why this requirement was not met.

1.3.4 Secondary Wiring

(1) No splices will be allowed in the current transformer secondary circuit except through the use of terminal block connections.

(2) The integrity of the secondary wiring of the current transformers shall be verified at initial certification and at least every three years thereafter.

(3) The metering circuit should be limited to highly accurate billing meters and load control transducers. Relays shall not be connected to the secondary metering circuit.

1.3.5 Grounding of Current Transformer Secondary Circuits

(1) A common return conductor shall be utilized for each set of isolated current transformer secondary windings.

(2) The common terminals of each set of current transformers shall be grounded at only one point.

(3) It is recommended that the ground connection be located at the meter or at the nearest terminal block to the meter.

(4) The ground conductor shall be, at a minimum, the same wire size as the smallest polarity conductor in the metering current circuit.

1.3.6 Induced Voltage

(1) Secondary circuits should be designed and routed so as to avoid the possibility of induced voltages and the effects of high ground fault voltages.

(2) Suitable protection against the effects of fault and switching generated over-voltages should be provided.

1.3.7 Paralleling of Current Transformers

(1) Paralleling of current transformers is not recommended. However, when it is necessary, the following requirements apply:

(a) All transformers must have the same nominal ratio regardless of the ratings of the circuits in which they are connected.

(b) All transformers which have their secondaries paralleled must be connected to the same phase of the primary circuits.

(c) The secondary circuits shall be connected in a configuration to allow for testing of individual instrument transformers. The secondary circuits shall be paralleled at the meter test switch.

(d) There shall be only one ground on the secondary of all paralleled transformers at their common point. It is recommended that the ground be located at the meter or at the nearest terminal block to the meter.

(e) Each current transformer must be capable of supporting **n** times the common burden plus its own individual burden, and stay within the accuracy class of the transformers, where n = number of current transformers in parallel. This is the effective burden for each current transformer.

(f) A common voltage must be available for the meter. This condition is met if the circuits share a common bus that is normally operated with closed bus ties.

(g) The meter must have sufficient current capacity to carry the sum of the currents from all the transformers to which it is connected.

(h) The secondary leads from all current transformers shall be such that the maximum possible burden placed on any transformer does not exceed its adjusted burden rating, as defined in paragraph (e) above.

1.3.8 Sizing of Current Transformers

(1) Current transformers shall be sized for optimum metering accuracy, considering peak, nominal and minimum loads, current transformer rated accuracy, rating factor, and ability to withstand available fault current.

(2) Optimum metering accuracy may require the use of the following:

(a) Rating factor greater than 1.0; and/or

(b) High accuracy, extended range current transformers.

1.3.9 Exceptions

(1) Exceptions would include bi-directional EPS Metering points in service on October 1, 2000 where under normal conditions (facility is generating electricity), large amounts of power flows into the ERCOT grid; and on occasion, when all generation behind this metering point is off-line, this same metering point will experience small amounts of power flow from the ERCOT grid into the facility. If changes to existing current transformers are required, the metering point shall no longer be classified as "in service on October 1, 2000." For these existing installations, the TDSP shall:

(a) Ensure good engineering design practices were met for this metering installation;

(b) Ensure metering equipment meets all applicable American National Standards Institute (ANSI) standards; and

(c) Ensure the current transformer is operating within its accuracy range at peak and nominal generation output.

(2) Example of good engineering design practice is when the current transformers are selected to maintain revenue metering accuracy at expected peak loads and still achieve acceptable accuracy at minimum loads, recognizing that these smaller loads may be outside the demonstrated accuracy range of the current transformer.

(3) At EPS Meter Facilities with an approved EPS Metering Design Proposal, current transformer replacement shall not be required based solely upon advancements in instrument transformer technology.

1.4 Voltage Transformers

1.4.1 Quantity

(1) Voltage transformers for a four-wire wye neutral grounded system (three single-phase units or one three-phase unit) shall be installed, one from each phase conductor to the circuit neutral.

(2) Voltage transformers (two single-phase units) for a three-wire ungrounded system shall be installed from each phase conductor that has a current transformer to the phase conductor in which there is no current transformer.

(3) Voltage transformers (three single-phase units or one three-phase unit) for a three-wire wye, neutral grounded transmission system may be installed from phase to ground on the primary and be used for two-stator metering. The Transmission and/or Distribution Service Provider (TDSP) must ensure the following conditions:

(a) The ERCOT-Polled Settlement (EPS) Metering Facility does not have equipment that provides a path for ground current (except insulators, surge arresters, voltage transformers) connected to the three-wire wye neutral grounded transmission system.

(b) The three metering voltage transformers must be connected to the grounding system of the transmission facility for the voltage reference.

(c) The meter potential elements shall be connected from phase to common phase on the secondary of the voltage transformers.

(d) The secondary circuit of the metering potentials shall be connected to the grounding system of the transmission facility.

(4) Voltage transformers (two single-phase units) may be installed from each phase conductor that has a current transformer to the phase conductor in which there is no current transformer; for metering of an EPS Metering Facility which is connected to a three-wire wye, high or low impedance grounded distribution system, if phase to ground loads or phase to ground sources are not connected behind the metering point and the high or low impedance ground is installed as part of a fault monitoring system for the facility.

(a) The TDSP shall verify the existence of the high or low impedance ground and the existence of the fault monitoring system during initial site certification and at least every three years thereafter. Such verification shall be documented on either the EPS Metering Test Report or the EPS Metering Site Certification Form.

(b) The Resource Entity shall provide written certification, sealed by a professional engineer registered in the State of Texas, that all power transformer primary connections behind the EPS metering point are ungrounded delta, ungrounded wye or phase to phase and that the system configuration, as connected behind the EPS metering point, will not support a phase to ground load connection. Such certification shall be submitted with the EPS Metering Design Proposal.

(c) For metering an EPS Metering Facility connected to a three-wire wye, high or low impedance grounded distribution system and not meeting these requirements, voltage transformers shall be installed from each phase conductor to the circuit neutral.

1.4.2 Burden

(1) The voltage transformer burdens shall be kept as small as practical.

(2) The total burden/volt-ampere rating of the voltage transformer shall not be exceeded.

1.4.3 Protection

(1) Secondary fuses should be of the high-speed, high current interrupting construction with low electrical impedance and the mechanical ruggedness to resist the effects of corrosion and vibration. The main purpose of fuses shall be for protection of personnel, the transformer, and the secondary wiring against accidental faults or shorts, rather than to protect the voltage components of the measuring devices. Fuses shall not be placed in the common secondary return or the ground circuit of instrument transformers.

1.4.4 Secondary Wiring

(1) All secondary wiring shall be designed such that the maximum voltage drop at the metering devices does not exceed 0.3 Volts. A voltage drop calculation or measurement shall be performed as part of the initial installation.

(2) The integrity of the secondary wiring of the voltage transformers shall be verified at initial certification and at least every three years thereafter.

(3) No splices will be allowed in the voltage transformer secondary circuit except through the use of terminal block connections.

1.4.5 Grounding of Voltage Transformer Secondary

(1) Each set of voltage transformer secondary windings shall have only one ground.

(2) It is recommended that the ground connection be located at the meter or at the nearest terminal block to the meter.

1.4.6 Induced Voltage

(1) Secondary circuits should be designed and routed so as to avoid the possibility of induced voltages and the effects of high ground fault voltages.

(2) Suitable protection against the effect of fault and switching generated over-voltages should be provided.

1.5 Metering Facility

1.5.1 Specification

(1) The environment for the ERCOT-Polled Settlement (EPS) Metering equipment shall be designed such as to maintain at all times the operating characteristics as stated by the equipment manufacturer.

(2) A clear space shall be provided in front of the meter as outlined in the latest revision of Institute of Electrical and Electronics Engineers (IEEE) C2, *The National Electric Safety Code*, Article 125a applicable at time of original installation.

1.5.2 Facilities for Testing

(1) Test switches should be located at, or near the metering devices. Where the test output of the meter is electrical rather than visual, provisions should be made to conveniently measure the test output.

(a) The meters and test facilities should be located inside an enclosure or structure that provides adequate protection of the equipment from the environment.

(b) Adequate lighting should be provided in the area of meters as required for testing, maintenance and adjustment.

(c) Test switches shall be wired to allow individual meters to be removed from service for testing without affecting other meters in the circuit.

(d) When an automatic current shorting "relay" test block is used to test meters, meters shall be wired such that the testing of individual meters does not affect other meters in the circuit.

1.6 Testing and Calibration

1.6.1 Test Equipment

(1) Test equipment and test standards used for the testing and/or calibration of instrument transformers and ERCOT-Polled Settlement (EPS) Meters shall be certified to values of accuracy and precision, which are equal to or better than the accuracy of the equipment under test.

1.6.2 Certification of Standards

(1) All field and laboratory test standards shall be certified traceable to the National Institute of Standards and Technology (NIST), on the most stringent time schedule required by the

American National Standards Institute (ANSI) or the Public Utility Commission of Texas (PUCT) Substantive Rules, with a minimum of an annual certification. The appropriate correction factors shall be utilized to determine percent registration and retained with the standard.

(2) Within the 12 months prior to testing, test equipment and test standards used for the testing and/or calibration of equipment used to determine Energy Storage Resource (ESR) auxiliary Load that is telemetered to an EPS Meter, shall be certified to values of accuracy and precision, which are equal to or better than the accuracy of the equipment under test.

1.6.3 Responsibility

(1) Except in those cases where the involved parties agree otherwise, the party installing and controlling the metering installation shall be responsible for any maintenance and calibration. The meter test personnel shall be qualified to test the metering installation.

1.6.4 Notification

(1) Notification to ERCOT shall be in accordance with the requirements of Protocol Section 10, Metering.

(2) Parties requesting notification of impending tests shall do so by written request to the Transmission and/or Distribution Service Provider (TDSP). The request shall provide contact information of the requestor.

1.6.5 Calibration Tolerance

(1) EPS Meters shall meet the percent accuracy tolerances for kWh testing listed in the table below:

Series Test Sequence

% Test Amp	Power Factor	Tolerance %
100	1.0	±0.15%
10	1.0	±0.15%
100	0.5 lagging	±0.3%

(2) The individual elements shall be tested for balance before installation to within ±1.0%. A final series test sequence shall be performed after any calibration adjustment.

(3) kVArh tests shall be performed at 100% and 10% test amps using a phase shift between 60 and 90 degrees from unity power factor. The percent tolerance for kVArh tests shall be ±0.3%.

1.7 Test Schedules and Records

1.7.1 Frequency of Testing

(1) ERCOT-Polled Settlement (EPS) Meters shall be tested in the meter's test mode on a frequency as defined in Protocol Section 10, Metering.

(2) At a minimum, the Resource Entity shall provide an updated Resource Entity Auxiliary Load Calculation Attestation Form (Section 11, Appendix D, Resource Entity Attestation for Calculation and Telemetry of Energy Storage Resource (ESR) Auxiliary Load Values) on an annual basis, within the same month of each year as the previous year's attestation.

1.7.2 Test Records

(1) The Transmission and/or Distribution Service Provider (TDSP) shall keep the meter test records for a period of at least six years after the date of the test.

(2) Upon written request to the TDSP, the most recent meter test record shall be provided to the designated EPS Metering Facility representative or duly appointed agent within ten Business Days.

1.8 TDSP Responsibility for Documentation Following Facility Testing or Maintenance

(1) The Transmission and/or Distribution Service Provider (TDSP) shall furnish the following ERCOT-Polled Settlement (EPS) Metering Facility information to ERCOT:

(a) For routine annual meter tests where no changes to the existing EPS Metering Facility occur, the TDSP shall forward the EPS Meter Test Reports to ERCOT within 14 days of the date of meter test.

(b) When changes to the EPS Metering Facility occur that affect settlement data or data retrieval, including calibration errors greater than twice the defined accuracy limit for the EPS Metering Facility, the TDSP shall promptly notify ERCOT and the designated EPS Metering Facility representative and make all reasonable efforts to forward site data to ERCOT and the designated EPS Metering Facility representative by 1000 the Business Day following such changes.

(c) Test Forms - EPS Meter test results shall be recorded on approved ERCOT Meter Test Report forms.

1.9 Resource Entity Responsibility for Documentation Following Testing or Maintenance of ESR Auxiliary Load Calculation or Equipment

(1) A Resource Entity that calculates Energy Storage Resource (ESR) auxiliary Load telemetry for provision to an ERCOT-Polled Settlement (EPS) Meter shall:

(a) When changes to the auxiliary Load calculation occur that affect the provision of the telemetry signal, the Resource Entity shall promptly notify ERCOT and the Transmission and/or Distribution Service Providers (TDSPs) for the site and make all reasonable efforts to forward site data to ERCOT and the TDSP representative by 1000 the Business Day following such changes.

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Section 2: Failure of Communication Facilities

March 1, 2021

2 FAILURE OF COMMUNICATION FACILITIES

2.1 ERCOT Settlement Communication Link Unavailable for EPS Meters

(1) During a disruption to the ERCOT Meter Data Acquisition System (MDAS) communication link to ERCOT-Polled Settlement (EPS) Meters, ERCOT shall:

(a) Make all reasonable efforts to provide general information to Transmission and/or Distribution Service Providers (TDSPs) using voice communications; and

(b) Inform TDSPs of the methods they shall use to provide meter data to ERCOT during the disruption period.

2.2 Resource Calculated Auxiliary Load Communication Link Unavailable for EPS Meters

(1) During a disruption to the Resource communication link to ERCOT-Polled Settlement (EPS) Meters, the Resource Entity shall:

(a) Make all reasonable efforts to provide general information to Transmission and/or Distribution Service Providers (TDSPs) on the restoration efforts and timelines; and

(b) Provide Operating Day meter data to ERCOT and the TDSPs, via the ERCOT and TDSP requested format and delivery method, as required to support settlements during the disruption period.

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Section 3: Documentation for EPS Metering Facilities

May 1, 2024

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3 DOCUMENTATION FOR EPS METERING FACILITIES

3.1 General

(1) The documentation in this Section shall be used to meet the requirements outlined in Protocol Section 10, Metering. ERCOT forms can be found on the ERCOT website.

3.2 Documentation Requirements

3.2.1 EPS Metering Design Proposal

(1) The ERCOT-Polled Settlement (EPS) Metering Design Proposal should be provided no less than 90 days prior to the cutover date for adding or removing any EPS Meter for settlements.

(a) Facility Information and Contact Information;

(b) Metering Facility Details;

(c) Detailed one-line drawing of facilities showing metering points;

(d) Auxiliary Load Telemetry Details (if applicable); and

(e) Other information as required.

3.2.2 Meter Information Package

(1) The Meter Information Package should be provided no less than seven days before the Transmission and/or Distribution Service Provider (TDSP) certification of the facility. Meter information for the primary and back-up metering installations must include:

(a) Meter Data Acquisition System (MDAS) configuration form; and

(b) Other information as required.

3.2.3 Site Approval Request Package

(1) The Site Approval Request Package should be provided within 60 days after the site has been certified and must include:

(a) Site Certification Form;

(b) EPS Meter Test Report;

(c) Copy of Meter Programming File;

(d) TDSP meter multiplier calculation sheet as prescribed in Section 3.3, Calculation Sheet Requirements;

(e) TDSP pulse multiplier calculation sheet as prescribed in Section 3.3;

(f) TDSP transformer and line loss compensation calculation sheet as prescribed in Section 3.3;

(g) Certification of instrument transformers. Such certification shall include the nameplate information and either a manufacturer’s certificate of test (preferred) or certification by a professional engineer registered in the State of Texas. Such certification shall include the criteria used to certify that such instrument transformer’s accuracy is in compliance with Protocol Section 10, Metering, and this Settlement Metering Operating Guide (SMOG);

(h) Redlined or final as built detailed one-line drawings of the complete metering facility and a three line drawing detailing the metering circuit with TDSP EPS Meter Inspector’s initials. Note: If a redlined version is supplied, the final as built drawings shall be submitted within 45 days of the submittal of the Site Approval Request Package;

(i) Readable photos of the nameplates of newly installed or replaced instrument transformers. When instrument transformers are physically located inside an apparatus and nameplate photos cannot be provided, a statement bearing the seal of a professional engineer registered in the State of Texas must be submitted instead of the nameplate photos. Such statement shall provide all nameplate information for the instrument transformer(s), a certification that the information provided represents the installed equipment, and the basis for the certification;

(j) Resource Entity Auxiliary Load Calculation Attestation Form (Section 11, Appendix D, Resource Entity Attestation for Calculation and Telemetry of Energy Storage Resource (ESR) Auxiliary Load Values), if applicable; and

(k) Other information as required.

3.2.4 TDSP Cutover Form

(1) The TDSP Cutover Form should be submitted 14 days before the requested “cutover” date.

(2) This form shall be submitted by the TDSP to facilitate the transfer of information required to add or remove an EPS Meter point in the ERCOT Data Aggregation System (DAS).

3.3 Calculation Sheet Requirements

3.3.1 TDSP Meter Multiplier (Internal Registers) Calculation Sheet

(1) This sheet from the Transmission and/or Distribution Service Provider (TDSP) shall convey the process used by the TDSP to calculate the multiplier that shall be applied to the readings retrieved via ERCOT Meter Data Acquisition System (MDAS) from ERCOT-Polled Settlement (EPS) Meters to calculate energy. This sheet shall include the following information:

(a) The written formula including all information used in the multiplier calculation;

(b) The multiplier calculation; and

(c) Rollover calculation for the readings.

3.3.2 TDSP Pulse Multiplier Calculation Sheet

(1) This sheet from the TDSP shall convey the process used by the TDSP to calculate the pulse multiplier that shall be applied to the interval data retrieved via ERCOT MDAS from EPS Meters to calculate energy. This sheet shall include the following information, as applicable:

(a) The written formula including all information used in the pulse multiplier calculation;

(b) The pulse multiplier calculation;

(c) Rollover calculation for the interval pulse data;

(d) Pulses per interval at maximum energy output or consumption; and

(e) Pulses per interval at nominal energy output or consumption.

3.3.3 TDSP Transformer and Line Loss Compensation Calculation Sheet

(1) This sheet from the TDSP shall convey the process used by the TDSP to calculate the transformer and line loss compensation for EPS Meters. This sheet can be accomplished by using the ERCOT example of loss calculation shown in Section 8.6.1, Transformer and Line Loss Compensation Sheet, or a TDSP calculation that meets the same standards. A TDSP-created sheet shall include all information required by Section 8.6.1 and the following additional information:

(a) Formula used to calculate loss compensation;

(b) Actual values entered into the formula; and

(c) Logic for calculation of losses if not at full transformer rating.

3.4 EPS Metering Facility Processes and Forms

(1) ERCOT shall make reasonable efforts to establish consensus in discussions with the Metering Working Group (MWG) prior to implementation of substantive revisions to existing or proposed EPS Metering Facility forms listed on the ERCOT-Polled Settlement Metering webpage.

ERCOT Settlement Metering Operating Guide

Section 4: EPS Meter Configuration Criteria

March 1, 2021

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4 EPS METER CONFIGURATION CRITERIA

4.1 Standard IDR Channel Assignments

(1) Interval Data Recorder (IDR) channel assignment programming for ERCOT-Polled Settlement (EPS) Meters shall conform to the following:

(a) Unidirectional meters for Loads:

(i) Channel 1 shall record active energy (kWh) flowing out of the ERCOT System;

(ii) Channel 2 shall record reactive energy (kVArh) flowing out of the ERCOT System (quadrant 1 plus quadrant 2); and

(iii) Channel 3 shall record reactive energy (kVArh) flowing into the ERCOT System (quadrant 3 plus quadrant 4).

(b) Bi-directional meters and generation meters with no Resource Entity calculated auxiliary Load:

(i) Channel 1 shall record active energy (kWh) flowing out of the ERCOT System;

(ii) Channel 2 shall record reactive energy (kVArh) flowing out of the ERCOT System (quadrant 1 plus quadrant 2);

(iii) Channel 3 shall record reactive energy (kVArh) flowing into the ERCOT System (quadrant 3 plus quadrant 4); and

(iv) Channel 4 shall record active energy (kWh) flowing into the ERCOT System.

[SMOGRR024: Insert paragraph (c) below upon system implementation of NPRR1020 and renumber accordingly:]

(c) Wholesale Storage Load (WSL) meters that include a Resource Entity calculated auxiliary Load:

(i) Channel 1 shall record active energy (kWh) flowing into the Energy Storage Resource (ESR);

(ii) Channel 2 shall record reactive energy (kVArh) flowing into the ESR (quadrant 1 plus quadrant 2); and

(iii) Channel 3 shall record reactive energy (kVArh) flowing out of the ESR (quadrant 3 plus quadrant 4).

(iv) Channel 4 shall record active energy (kWh) flowing out of the ESR.

(v) Channel 5 shall record auxiliary Load active energy (kWh) from Resource Entity provided Real-time telemetry.

(c) WSL meters that include a Resource Entity calculated auxiliary Load and a Transmission and/or Distribution Service Provider (TDSP) calculated Wholesale Storage Load (WSL):

(i) Channel 1 shall record active energy (kWh) flowing into the Energy Storage Resource (ESR);

(ii) Channel 2 shall record reactive energy (kVArh) flowing into the ESR (quadrant 1 plus quadrant 2); and

(iii) Channel 3 shall record reactive energy (kVArh) flowing out of the ESR (quadrant 3 plus quadrant 4).

(iv) Channel 4 shall record active energy (kWh) flowing out of the ESR.

(v) Channel 5 shall record auxiliary Load active energy (kWh) from Resource Entity provided Real-time telemetry.

(vi) Channel 6 shall record the WSL calculated active energy (kWh) used to charge the ESR.

(2) TDSPs may utilize other recording channels, on EPS Meters equipped with more than the required channels, for additional data recording, provided the utilization of such channels does not interfere with the EPS Meter settlement requirements or the ability of the Meter Data Acquisition System (MDAS) to retrieve the settlement data. In addition, the interval length for any optional channels retrieved by MDAS shall be consistent with the settlement data interval. Use of more than 16 channels shall require ERCOT approval.

4.2 Display Modes

4.2.1 Normal Display Modes

(1) ERCOT does not require any display items in the meter's normal display mode. The values displayed in the normal display mode will be determined by the Transmission and/or Distribution Service Provider (TDSP).

(2) The TDSP shall ensure that ERCOT-Polled Settlement (EPS) Meters are programmed in a manner that allows the ERCOT Meter Data Acquisition System (MDAS) to associate internal register readings with the correct recorder interval channel for settlement.

(3) The meter shall be programmed such that the internal register readings retrieved by ERCOT do not roll over in less than 45 days.

4.2.2 Alternate Display Mode

(1) ERCOT does not require any display items in the meter's alternate display mode. The values displayed in the alternate display mode will be determined by the TDSP.

4.2.3 Test Mode Display

(1) ERCOT does not require any display items in the meter's test mode. The values displayed in the test mode will be determined by the TDSP.

4.3 Transformer and Line Loss Compensation

(1) Transformer and line loss compensation to ERCOT-Polled Settlement (EPS) Meters shall be performed in accordance with Protocol Section 10, Metering, and this Settlement Metering Operating Guide (SMOG).

4.4 Flagging of Interval Data for Power Outage

(1) A maximum power outage length of three seconds shall be used for flagging intervals when voltage to the meter's power supply is lost.

4.5 Programming of Event Log Reporting

(1) Meters shall log and report the events, outlined in Section 6, General Specifications for ERCOT-Polled Settlement (EPS) Meters, when interrogated by the ERCOT Meter Data Acquisition System (MDAS).

4.6 Interval Data Recorder Resolution

4.6.1 Pulse Resolution

(1) The pulse multiplier should be chosen such that, at a minimum, 25% of the maximum allowable pulses per interval are recorded at nominal energy flow, while ensuring that the maximum pulses per interval for the device are not exceeded. In addition, the capabilities

of the ERCOT Meter Data Acquisition System (MDAS) regarding maximum pulses shall not be exceeded.

4.6.2 Engineering Units Resolution

(1) The selected rate of accumulation should be chosen using sound engineering practices to minimize the chances of energy being shifted from one settlement interval to another settlement interval. In addition, the capabilities of the ERCOT MDAS regarding engineering units shall not be exceeded.

4.7 Special Applications, Configurations and Unique Situations

(1) Transmission and/or Distribution Service Providers (TDSPs) are responsible for providing ERCOT with the necessary access to ERCOT-Polled Settlement (EPS) Meters and other information to enable ERCOT to prepare Settlement Quality Meter Data.

(2) For instance, where there is a generating plant with multiple generators and auxiliary loads, the TDSP must provide appropriate information (i.e., documentation, descriptions, one-line diagrams, etc.) to ERCOT to ensure that ERCOT can properly account for the net generator output under all combinations of generation and load (e.g. where only one generator is operating but all auxiliary loads are being supplied).

ERCOT Settlement Metering Operating Guide

Section 5: General Standards for EPS Metering Facilities

March 1, 2021

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5 GENERAL STANDARDS FOR EPS METERING FACILITIES

5.1 General

(1) The standards for ERCOT-Polled Settlement (EPS) Metering Facilities referred to in Section 5, General Standards for EPS Metering Facilities, provide additional details to the standards referred to in the ERCOT Protocols and apply to EPS Meters used in ERCOT for Settlement purposes.

5.2 General Standards for EPS Metering Facilities

(1) EPS Metering Facilities shall meet the following general standards:

(a) Instrument transformers used in Settlement Metering Facilities must meet the requirements in this Settlement Metering Operating Guide (SMOG).

(b) Settlement meters must meet the requirements in this SMOG.

(c) Meters must be remotely accessible, 60 Hz, three-phase, programmable and multifunction electronic meters.

(d) To minimize the loss of energy data during line outage conditions, a highly reliable source of auxiliary power should be utilized.

(e) Meters must be capable of being remotely time synchronized by ERCOT (Meter Data Acquisition System (MDAS)).

(f) Meters must be capable of measuring kWh and kVArh.

(g) Meters must have battery back-up for maintaining Random-Access Memory (RAM) and a Real-Time clock during outages of up to 30 days.

(h) The meter must be capable of remote interrogation by the ERCOT MDAS.

(i) The meter must be capable of 45 days' storage of interval data for each of the required channels.

(j) Metering equipment connected to the telephone circuit shall be protected with adequate surge protection.

5.3 Detailed Standards for EPS Meters

(1) Section 6, General Specifications for EPS Meters, provides the detailed specifications with which ERCOT-Polled Settlement (EPS) Meters must comply.

5.4 Detailed Standards for Instrument Transformers

(1) Section 7, General Specifications for Instrument Transformers for EPS Metering, provides the detailed specifications with which instrument transformers used with an ERCOT-Polled Settlement (EPS) Meter must comply.

5.5 Detailed Standards for Resource Entity-Owned Equipment Used for the Calculation of the Auxiliary Load Telemetry Provided to the EPS Meter

(1) Data Recording Function for Calculated Auxiliary Load:

(a) Auxiliary Load calculated data shall be stored in a Resource Entity storage device such that a minimum of 45 days of 15-minute interval energy is available; and

(b) Recording of data shall continue while communicating through any communications port.

(2) Calculated auxiliary Load must be telemetered to both the primary and backup ERCOT-Polled Settlement (EPS) Meter.

(3) The EPS Meters must be updated with an auxiliary Load calculation at least every four seconds.

ERCOT Settlement Metering Operating Guide

Section 6: General Specifications for EPS Meters

March 1, 2021

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6 GENERAL SPECIFICATIONS FOR EPS METERS

6.1 Application

(1) This Section applies to all ERCOT-Polled Settlement (EPS) Meters.

6.2 Scope

(1) This Section 6, General Specification for EPS Meters, provides the minimum functional and performance requirements for ERCOT-Polled Settlement (EPS) Meters. Meters used for EPS Metering shall comply with all applicable American National Standards Institute (ANSI) C12 standards.

6.3 Metering Functions

6.3.1 Measured Quantities

(1) The following energy quantities are required for ERCOT-Polled Settlement (EPS) Meters:

(a) kWh—flowing out of the ERCOT System;

(b) kVArh—flowing out of the ERCOT System (quadrant 1 plus quadrant 2);

(c) kVArh—flowing into the ERCOT System (quadrant 3 plus quadrant 4); and

(d) kWh—flowing into the ERCOT System.

6.3.2 Basic Default Metering Function

(1) The EPS Meter's program shall be stored in non-volatile memory.

6.3.3 Data Recording Function

(1) EPS Meters shall have the following interval data recording functions:

(a) Provide recording of interval data for a minimum of four channels;

(b) Use a "wraparound" memory that stores new interval data by writing over the oldest interval data;

(c) Interval data shall be stored for a minimum of 45 days of required channel, 15-minute interval data, in addition to allowances for event recording (power outages, resets, time sets, etc.);

(d) The recording of interval data function shall have the capacity to count and store at least 4,000 counts in a 15-minute period of time; and

(e) Recording of interval data shall continue while the meter is communicating through any communications port.

6.3.4 Functions during Power Outage to Meter Power Supply

(1) EPS Meters shall have the following functions during a power outage to the meter power supply:

(a) During outage conditions the meter shall maintain all meter data as well as time keeping functions. Display and communication functions are not required during these conditions.

(b) The meter shall withstand the following outages without the need to maintain its power supply including replacing the battery:

(i) Twenty short outages per year of less than 30 seconds per outage; and

(ii) Thirty days of continuous/cumulative outage.

(c) During a power outage, critical program and billing data shall be written to non-volatile memory. When power is restored, data shall be returned to active memory and data collection resumed.

(d) Upon restoration of power after an outage, the meter shall resume normal calculation of consumption and demand quantities. Optional outputs shall also resume normal function.

(e) During power outages, time shall be maintained with a cumulative error of no more than two minutes per week (0.02%).

(f) The meter shall record the date and time of any power outage and may also record the duration of any power outage.

6.3.5 Meter Test Mode Function

(1) EPS Meters shall have the following meter “test mode” functions:

(a) The meter shall have the capability of a “test mode” function that suspends normal metering operation during testing so that additional consumption and demand from the tests are not added to the meter’s totals. This includes the normal mode display registers and the interval data. This requirement is imposed to prevent the test data from being recorded as actual load/generation data.

(b) Security shall be provided to prevent unauthorized access to the “test mode.”

(c) Activation of the test mode shall cause all present critical billing data to be stored in non-volatile memory and restored at the time of exit from the "test mode."

(d) The meter shall be programmed to automatically exit the "test mode" and return to normal operation after one hour or less of operator inactivity.

6.4 Consumption and Recording Requirements

6.4.1 Constants and Compensation Values

(1) The ERCOT-Polled Settlement (EPS) Meter shall be programmable to account for radial line losses and power transformer loss compensation as needed.

(2) The EPS Meter shall be programmable to display and record the compensated values. The values will be programmable in kWh, kVArh, etc.

6.4.2 Identifiers

(1) The EPS Meter shall have a unique identifier for the Meter Data Acquisition System (MDAS) ID. The MDAS ID shall be capable of at least seven alphanumeric characters and shall be programmed internal to the meter.

6.5 Meter Diagnostics

6.5.1 Self-test Frequency

(1) The ERCOT-Polled Settlement (EPS) Meter shall be capable of performing a self-test. At a minimum, the self-test shall be performed at the following times:

(a) Whenever communications are established to the meter;

(b) After a power-up; and

(c) Once per day.

6.5.2 Self-test Checks

(1) Upon failure of a self-test, the meter shall store an event log to be retrieved by the Transmission and/or Distribution Service Provider (TDSP) and/or ERCOT Meter Data Acquisition System (MDAS). At a minimum, the following checks shall be performed during a self-test:

(a) Check the backup battery usage or voltage;

(b) Verify the program integrity; and

(c) Verify the memory integrity.

6.5.3 Pulse Overrun

(1) The EPS Meter shall be capable of detecting and reporting to the TDSP and/or ERCOT MDAS if the maximum pulses per interval have been exceeded during an interval.

6.5.4 Event Logging

(1) EPS Meters shall be capable of logging the following events:

(a) **Hardware Errors:** Various hardware malfunctions (i.e., modem card/chip, measurement chip, central processing unit (CPU), etc.), whether fatal or not.

(b) **Firmware Errors:** Firmware has a checksum error, watchdog time out error, or other problem with the firmware, whether fatal or not.

(c) **Random-Access Memory (RAM) and Read-Only Memory (ROM) Errors:** Bad spots in memory identified via checksum or other means.

(d) **Pulse Overflow Errors:** The maximum size value for the number of pulses per interval in Load Profile has been exceeded. This does not apply to meters that store/report data in engineering units.

(e) **Low Battery Condition:** Low battery has been sensed during initial power up, daily self checks, after power outages, or any other means to check for a low battery condition.

(f) **AC Power Up:** When the meter electronics are powered up either via auxiliary power or connected to system power.

(g) **AC Power Down:** When the meter electronics loses power either by auxiliary power or connected to system power.

(h) **Configuration Changed:** Meter has been reprogrammed, or any meter programming where a settlement metering parameter is changed.

(i) **Clock Set/Change:** The meter Real-Time clock has been set/changed by external sources.

(j) **Test Mode Activation:** Meter going into and out of “test mode.”

(k) **Inactive Potential/Phase Failure:** System phase voltage falls below 75% – 85% of the nominal voltage value for 0 – 10 second(s). Nominal value for this event is defined as the primary or secondary voltage rating of the voltage transformer to which the EPS meters are connected, as specified on the name plate, manufacturer test report or Professional Engineer letter. The ability to log subsequent inactive potential events shall occur once voltage is greater than 75% – 95% of nominal for 0 – 10 second(s). The TDSP shall ensure that the meter set points are within the specified ranges for the voltage and time thresholds referenced above.

(l) **Loss of telemetry:** For meters that have a telemetered Wholesale Storage Load (WSL) auxiliary Load signal, the loss of the signal shall be recorded.

(m) **Restoration of telemetry:** For meters that have a telemetered WSL auxiliary Load signal, the restoration of the signal after a loss shall be recorded.

(2) The events described in paragraph (1) above shall be reported when interrogated by ERCOT MDAS.

6.5.5 Error Reset

(1) Fatal error or warning conditions shall only be reset upon an explicit command invoked via the meter programmer or upon some other explicit action by the TDSP EPS Meter Inspector.

6.6 Communication

6.6.1 Local Communications Interface

(1) The ERCOT-Polled Settlement (EPS) Meter shall be capable of communicating with a handheld reader or personal computer through a local port.

6.6.2 Internal/External Modem

(1) Internal or external modems shall be capable of telephone communications at baud rates at a minimum of 1,200 baud. The ring detect circuitry shall not be affected by transient voltage rises in the telephone line.

6.7 Accuracy Standards

6.7.1 Accuracy Class

(1) ERCOT-Polled Settlement (EPS) Meters shall meet or exceed the accuracy specifications contained in American National Standards Institute (ANSI) C12.20, 0.2 and 0.5 Accuracy Classes.

6.7.2 Test Equipment

(1) EPS Meter accuracy and calibration tests, both shop and field, shall require only standard test equipment traceable to the National Institute of Standards and Technology (NIST). No special laboratory-type test equipment or test procedures shall be required to assure the accuracy of the meter.

(2) Test equipment used to certify the Energy Storage Resource (ESR) auxiliary Load calculation shall be traceable to the NIST.

6.7.3 Start-up Delay

(1) The EPS Meter shall start to calculate consumption and demand quantities within 15 seconds after power application to the metering electronics.

6.8 Electrical Requirements

6.8.1 Meter Forms, Voltage Ratings and Classes

(1) ERCOT-Polled Settlement (EPS) Meters shall be an approved American National Standards Institute (ANSI) form and comply with applicable ANSI C12 standards. Two and one-half element meters shall not be used as EPS Meters. The meter shall be Transmission and/or Distribution Service Provider (TDSP)-approved Class 2, Class 10, or Class 20.

6.8.2 Clock

(1) The EPS Meter's internal clock shall be accurate within two minutes per week (±0.02%) when not synchronized to the ERCOT System line frequency and shall be re-settable through the ERCOT communications interface.

6.9 Meter Package

(1) The ERCOT-Polled Settlement (EPS) Meter package shall comply with American National Standards Institute (ANSI) C12.10, Physical Aspects of Watthour Meters – Safety Standard, requirements where applicable. Switchboard/panel-board meters shall be in accordance with applicable National Electrical Safety Code (NESC) standards and must be mounted indoors or in an enclosure that meets all applicable National Electrical Manufactures Association (NEMA) standards.

6.10 Meter Password

(1) The ERCOT-Polled Settlement (EPS) Meter shall be programmable with a minimum of two unique passwords, one being a read only password, to prevent unauthorized tampering by use of the optical port or the modem. Passwords must be a minimum of four alphanumeric characters. Access rights and capabilities shall be individually programmable for each password.

6.11 Data Security and Performance

(1) No error, lockup or loss of data shall occur as a result of the following events:

(a) Power outages, frequency changes, transients, harmonics, reprogramming (except re-initialization), time sync, or any meter communications;

(b) Environmental factors—e.g., dampness, heat, cold, vibration, or dust; and

(c) Multiple communication requests from different sources.

6.12 EPS Meter Approval

6.12.1 General Requirement

(1) This Section 6.12, EPS Meter Approval, outlines the required testing a meter manufacturer must perform to assure the quality of ERCOT-Polled Settlement (EPS) Meters.

(a) All meters shall be in compliance with the latest revision of American National Standards Institute (ANSI) C12.20 at the 0.2 Accuracy Class, ANSI C12.1 and other ANSI C12 standards.

(b) Any applicable tests required ensuring such meter meets the requirements specified in this Settlement Metering Operating Guide (SMOG) and Protocol Section 10, Metering.

6.12.2 TDSP EPS Meter Conformance Requirements

(1) Transmission and/or Distribution Service Providers (TDSPs) retain the responsibility for assuring the accuracy, integrity and Meter Data Acquisition System (MDAS) compatibility of EPS Meters. This Section 6.12.2, TDSP EPS Meter Conformance Requirements, outlines the minimum TDSP requirements to ensure EPS Meters conform to this SMOG and the Protocols. TDSPs may develop additional acceptance criteria with respect to EPS Meter selection without the approval of ERCOT.

(2) Each TDSP shall maintain the following documentation for all meters they approve for use on EPS Meter installations:

(a) List of all meter manufacturer(s) and type(s) used, including:

(i) Firmware version – date deployed and date discontinued including reason for discontinuation.

(ii) Software version – date deployed and date discontinued including reason for discontinuation.

(b) Manufacturer's letter certifying compliance with applicable industry standards (ANSI), this SMOG, and applicable sections of ERCOT Protocols.

(c) Manufacturer's documentation detailing testing certification to the applicable industry standard (ANSI), compliance with this SMOG and applicable sections of ERCOT Protocols.

(d) Drawing(s) showing external meter connections.

(e) Manufacturer's instruction booklets detailing the necessary procedures and precautions for installation of the meter by field personnel including a step-by-step outline.

(f) Manufacturer's technical/maintenance manual for each meter style. The manuals shall be sufficiently detailed so that circuit operation can be understood.

(g) Software and associated documentation for the following:

(i) Programming;

(ii) Diagnostics; and

(iii) Data retrieval (meter reading).

(3) Each TDSP shall ensure that the ERCOT MDAS can successfully communicate with any meter the TDSP approves for EPS use.

6.12.3 Changes to an Approved EPS Meter

(1) EPS Meter manufacturers shall notify the TDSP of any changes to an approved meter that may affect such meter's compliance with Section 6.12, EPS Meter Approval.

(a) Meter manufacturers shall document and provide information to the TDSP on manufacturer firmware changes or updates for such meter. Such information shall include the implementation date of such changes and the specific effects of such changes. Such changes should be documented by meter serial number. Notification of such changes shall be provided in a timely manner.

(b) Meter manufacturers shall document and provide information to the TDSP on manufacturer design changes for such meter. Such information shall include the implementation date of such changes and the specific effects of such changes. Such changes should be documented by meter serial number. Notification of such changes shall be provided in a timely manner.

(2) The TDSP shall evaluate such manufacturer changes to ensure the compliance to the Protocols and this SMOG before using such changed meter as an EPS Meter. The TDSP shall notify ERCOT in writing of any such changed meter that did not pass the compliance evaluation and fully explain the reason the meter did not pass.

(3) The TDSP shall notify ERCOT in writing of any EPS Meter identified with a problem by the TDSP or the meter manufacturer. This notification shall include:

(a) The identified problem;

(b) Meter serial number;

(c) The process the TDSP intends to implement to correct the problem(s);

(d) A proposed timeline for problem resolution; and

(e) The estimated effect on meter accuracy for the time period the meter was and will be used to provide settlement data.

6.12.4 ERCOT Role regarding EPS Meters

(1) ERCOT shall rely upon the TDSP for approval, verification, documentation and certification of EPS Meters. However, ERCOT shall have the right to request compliance and certification documentation from meter manufacturers (for confidential material) and the TDSPs.

(2) ERCOT shall notify TDSPs of EPS Meter problems disclosed to ERCOT as a result of TDSP product change evaluation or EPS Meter failure.

(3) ERCOT shall assist the TDSP to ensure that MDAS successfully communicates with the EPS Meter being tested for approval.

ERCOT Settlement Metering Operating Guide

Section 7: General Specifications for Instrument Transformers for EPS Metering

June 1, 2022

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7 GENERAL SPECIFICATIONS FOR INSTRUMENT TRANSFORMERS FOR EPS METERING

7.1 Purpose

(1) This Section 7, General Specifications for Instrument Transformers for EPS Metering, specifies the technical requirements for current transformers and voltage transformers to be used for ERCOT-Polled Settlement (EPS) Metering Facilities.

7.2 Application

(1) This Section 7, General Specifications for Instrument Transformers for EPS Metering, applies to the following:

(a) Single-phase current transformers;

(b) Single-phase voltage transformers;

(c) Single-phase combination current/voltage transformers; and

(d) Coupling capacitor voltage transformers.

7.3 Standards

(1) All instrument transformers covered by this Section 7, General Specifications for Instrument Transformers for EPS Metering, shall be designed, manufactured, tested and supplied in accordance with the applicable American National Standards Institute (ANSI)/Institute of Electrical and Electronics Engineers (IEEE) standards and as required by the ERCOT Protocols and this Settlement Metering Operating Guide (SMOG).

7.4 Definitions

(1) Refer to the latest edition of the Edison Electric Institute (EEI) Handbook for Electricity Metering and Protocol Section 2, Definitions and Acronyms.

7.5 Specifications

7.5.1 General

(1) All instrument transformers covered by this Section shall meet the minimum Basic lightning impulse Insulation Level (BIL) rating, as specified in American National Standards Institute (ANSI) C12.11 or Institute of Electrical and Electronics Engineers

(IEEE) Standard C57.13-1993 Table 2, appropriate for the designated nominal system voltage or the latest ANSI standard.

7.5.2 Nameplate Data

(1) Nameplate information should conform to IEEE C57.13, IEEE Standard Requirements for Instrument Transformers, in effect at the time of instrument transformer manufacture.

7.5.3 Current Transformers

(1) Current transformers shall be wire wound.

7.5.3.1 Current Transformer Windings

(1) Current transformer windings (typical configurations) shall be either:

(a) Single primary winding and single secondary winding with single or multi ratio tap(s);

(b) Dual primary winding and a single ratio tap;

(c) Single primary winding and one or more secondary windings with single or multi ratio tap(s); or

(d) Other combinations as available and approved by ERCOT.

7.5.3.2 Rated Primary Current

(1) The rating selected for primary current must be as specified by the Transmission and/or Distribution Service Provider (TDSP) based on supplied information.

7.5.3.3 Rated Secondary Current (Wire Wound)

(1) The rated secondary current must be five amperes at rated primary current.

7.5.3.4 Reserved

7.5.3.5 Accuracy (Wire Wound)

(1) All current transformers shall have an accuracy of:

(a) Standard – 0.3% accuracy class; or

(b) Optional – 0.15 % accuracy class.

7.5.3.6 Reserved

7.5.3.7 Continuous current rating factor

(1) All current transformers shall meet or exceed a continuous current rating factor of:

(a) Standard – 1.5 at 30 degrees C Ambient; or

(b) Optional – 1.0 at 30 degrees C Ambient.

7.5.3.8 Short time thermal current rating

(1) The short time thermal current rating shall meet the standards defined in IEEE Standard C57.13 – 1993 or the latest C57.13 Standard.

7.5.3.9 Mechanical short time current rating

(1) The mechanical short time current rating shall meet the standards defined in IEEE Standard C57.13-1993 or the latest C57.13 standard.

7.5.4 Voltage Transformers

7.5.4.1 Transformer windings

(1) Transformer windings shall consist of a single primary winding and one or more tapped secondary windings.

7.5.4.2 Rated primary voltage

(1) Rated primary voltage will be specified by the TDSP.

7.5.4.3 Rated secondary voltage

(1) Rated secondary voltage will typically be 115/69 volts.

7.5.4.4 Accuracy

(1) All voltage transformers shall have accuracy of:

(a) Standard – 0.3% accuracy class; or

(b) Optional – 0.15% accuracy class.

7.5.4.5 Thermal burden rating

(1) The thermal burden rating of voltage transformers shall meet the standards defined in IEEE Standard C57.13-1993 or the latest C57.13 standard

7.5.5 Combination Current/Voltage Transformers (Metering Units)

(1) Combination current/voltage transformers shall maintain the same electrical, accuracy and mechanical characteristics as individual current transformers and voltage transformers. Physical dimensions may vary according to design.

7.6 Testing

(1) The Transmission and/or Distribution Service Provider (TDSP) shall ensure that each transformer is subjected to testing as prescribed by Institute of Electrical and Electronics Engineers (IEEE) Standard C57.13-1993 or the latest C57.13 standard.

(2) The accuracy test results shall be submitted to ERCOT as outlined in Section 3, Documentation for EPS Metering Facilities.

ERCOT Settlement Metering Operating Guide

Section 8: Transformer, Line Loss, and Series Reactor Compensation Factors

June 1, 2025

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8 TRANSFORMER, LINE LOSS, AND SERIES REACTOR COMPENSATION FACTORS

8.1 Introduction

(1) Transformer, line loss, and series reactor compensation refers to the practice of metering electrical energy delivered at a billing point using metering equipment connected away from the delivery point. The metering equipment is provided with a means of correction that adds to, or subtracts from, the actual active and reactive metered values in proportion to losses that are occurring in the transformer, lines, and series reactors.

(2) ERCOT approval is required for loss compensation performed in the Data Aggregation System (DAS). For a specific site, where a Transmission and/or Distribution Service Provider (TDSP) is requesting ERCOT to perform loss compensation in DAS, the TDSP shall submit to ERCOT, for approval, a single percent loss correction value and supporting documentation verifying such value. Such loss compensation percentage values and supporting documentation shall be resubmitted to ERCOT on an annual basis or upon circuit parameter changes.

(3) Transformer losses are divided into two parts:

(a) The core or iron loss (referred to as the no-load loss); and

(b) The copper loss (referred to as the load loss).

(i) Both the no-load loss and the load loss are further divided into Watt and VAr components.

(ii) The no-load (iron) loss is composed mostly of eddy current and hysteresis losses in the core. No-load loss varies in proportion to applied voltage and is present with or without load applied. Dielectric losses and copper loss due to exciting current are also present, but are generally small enough to be neglected.

(iii) The load (copper) watt loss (I^2 + stray loss) is primarily due to the resistance of conductors and essentially varies as the square of the load current. The VAr component of transformer load loss is caused by the leakage reactance between windings and varies as the square of the load current.

(4) Line losses are considered to be resistive and have I2R losses. The lengths, spacings and configurations of lines are usually such that inductive and capacitive effects can be ignored. If line losses are to be compensated, they are included as part of the load losses (Watts copper).

(5) Series reactor losses are to be calculated and compensated as percent Watt copper loss and percent VAr copper loss.

(6) The calculation for compensation of components on the Resource side of the billing point should result in a compensation that will raise the measured load values and lower generation values. The calculation for compensation of components on the TDSP side of the billing point should result in a compensation that will lower the measured load values and raise generation values. Once the data is made available, the TDSP shall ensure correct calculation and meter programming is utilized to correctly adjust the recorded values as required for the specific meter point configuration.

(7) The owner of any device for which compensation is required, i.e. a device connected between the meter point and the billing point, shall provide to the TDSP all data required to perform the calculation of the compensation factors for that device.

8.2 Calculating Transformer Loss Constants

(1) Transformer loss compensation calculations with electronic meters are accomplished internally with firmware. Various setting information and test data is required to program the meter. The following information is required regarding meter installations:

(a) Transformer high voltage rating;

(b) Transformer kVA rating;

(c) Transformer high voltage tap settings;

(d) Transformer low voltage tap settings;

(e) Transformer connection (wye or delta);

(f) Transformer phases (one or three);

(g) Voltage transformer ratio;

(h) Current transformer ratio;

(i) Number of meter elements;

(j) Meter class; and

(k) Meter volts.

(2) The following data is required from a transformer test report:

(a) No-load (iron) loss;

(b) Full-load (copper) loss;

(c) Percent impedance; and

(d) Percent excitation current.

(3) The test data required may be obtained from the following sources:

(a) The manufacturer's test report; or

(b) A test completed by a utility or independent electrical testing company.

8.3 Transformer Load Tap Changer

(1) Transformers equipped with a load tap changer (i.e., which have the capability to change transformer voltage tap positions or settings under Load) for regulating voltage, must have the loss compensation calculated at the median tap voltage.

(2) When calculating the compensation for auto-transformers that are in the Transmission and/or Distribution Service Provider (TDSP) rate base:

(a) Iron losses will be part of system losses; and

(b) Copper losses for the tertiary winding will need to be calculated to the highest voltage winding

(3) All meters shall have their loss compensation calculations based on the methodology used in the ninth edition of the Edison Electric Institute (EEI) Handbook for Electricity Metering.

8.4 Calculating Line Loss Constants

(1) Line loss compensation calculations with electronic meters are accomplished internally with firmware. Various information about the radial line is required to calculate the value, which is programmed into the meter.

(2) The following information is required about the line:

(a) Line type;

(b) Ohms per mile; and

(c) Length in miles of each type of line.

(3) Line loss compensation is not required for:

(a) Losses in a network connected line; or

(b) Sections of line where the calculated watts copper loss percentage is less than 0.001%.

(i) The calculation to determine the percent watts copper loss percentage shall follow the calculation example shown in Section 8.6.1, Transformer and Line Loss Compensation Sheet, utilizing the maximum meter current for the site in place of meter class amps divided by two. A power factor of 0.95 and an increase of 10% to the maximum expected power for the site shall be used to determine maximum meter current.

(ii) Increases in maximum site power above the expected power used in the calculation shall require reverification of compliance with this Section.

8.4.1 Switched Lines

(1) Line loss compensation for radial lines, which are switched, must be based on a negotiated average resistance based on the typical operating characteristics.

8.4.2 Joint Use Facilities

(1) In the case of joint use facilities (where facilities are used to deliver power to more than one entity) a fixed factor for losses is calculated based on the facilities' peak load. Such fixed factor shall be applied to the energy measured by each meter.

8.5 Reference Materials

(1) The following additional references may be referred to for assistance when calculating the compensation factors referred to in this Section 8, Transformer Line Loss, and Series Reactor Compensation Factors.

(a) Handbook For Electricity Metering, Edison Electric Institute, Ninth Edition, 1992.

(b) Institute of Electrical and Electronics Engineers (IEEE) Std. C57.12.00-2000, IEEE Standard General Requirements for Liquid Immersed Distribution, Power and Regulating Transformer.

(c) IEEE Std. C57.16-2011, IEEE Standard for Requirements, Terminology, and Test Code for Dry-Type Air-Core Series Connected Reactors.

8.6 Attachment

8.6.1 Transformer and Line Loss Compensation Sheet

Name:
Delivery:
Location:

Rev. Date:

HV Rated Voltage:	V	VT Ratio:	:1
HV Tap:	V	CT Ratio:	:5
LV Tap:	V	Joint Use (Y/N):	
Trf. Conn. (Y/D):		Metering Trf. Use:	100 %
Trf. Phase (1 or 3)		Contract kW:	kW
# Meter Elem.:		Power Factor:	%

Comments:

TRANSFORMER DATA

Serial Number	KVa Rating	No Load (Fe) Loss	Load (Cu) Loss	(Z) Impedance	(IE) Exciting Current

Total kVa rating:	Max Available kVa:

LINE DATA

	Resistance	Length
#1 Line Type:	Ohms/mile	Miles
#2 Line Type:	Ohms/mile	Miles
#3 Line Type:	Ohms/mile	Miles
#4 Line Type:	Ohms/mile	Miles
#5 Line Type:	Ohms/mile	Miles
#6 Line Type:	Ohms/mile	Miles

SERIES REACTOR DATA

Serial Number	Rated Current	Rated Voltage	Resistance (Ohms)	Inductance (mH)

****TRANSFORMER LOSS COMPENSATION TEST POINTS FOR WATTHOURS****

SERIES TEST

Test Load	% Total
Full	
0.5 P.F.	
Light	

****TRANSFORMER LOSS COMPENSATION TEST POINTS FOR VARHOURS****

SERIES TEST

Test Load	% Total
Full	
Light	

Example: Transformer, Series Reactor, and Line Loss Compensation Calculation Sheet

Date: XX/XX/20XX							
Transformer Information		**Transmission Line Information**		**Series Reactor Information**		**Meter Information**	
Xfmr Manufacturer	ABB	Line Type	4/0 ACSR	Reactor Manufacturer	GE	PTR (xxx/1)	60
Xfmr Serial Number	1000001	Line Length (miles)	7.360	Reactor Serial Number	3543130010, 3543130011, 3543130012	CTR (xxx/1)	120
Xfmr size (KVA)	12000	Line Res. @ 50 C	0.592	Reactor Rated Current	1200	Meter Rated volt (V)	120
Xfmr Pri. test volt (p-p-v)	110000	*Total Line Res.	4.357	Average Series Reactor Reactance (Ohms=2*π *60Hz*mH*10^{-3})	0.12*π *2.477	Meter class (amp)	20
Xfmr. sec. test volt (p-p-v)	13090	*Line Loss (VA)	266549	Average Series Reactor Resistance (Ohms)	0.00731323	Number of elements	3
Xfmr. No-Load loss (Watts)	22200					*Meter Nominal Watts (Watts)	3600
Xfmr. Excitation Current (%)	0.45					*Nominal CT Primary amp (A)	1200
Xfmr. Load loss (Watts)	51360					* Meter secondary test volt (V)	125.9586
Xfmr Impedance (%)	8.84					*Nominal Primary VA (VA)	25920000
*Xfmr sec. Test amp (A)	529.27						
*Xfmr Pri Amps @ 1/2 Mtr Cl (A)	142.80						

XFMR Loss Constants	
*No Load VA loss (VA)	54000
*No Load loss phase angle (alpha)	65.73
*No Load VAr loss (VAr)	49226
*Load VA loss (VA)	1060800
*Load loss phase angle (beta)	87.22
*Load VAr loss (VAr)	1059556

Series Reactor Losses	
*SR Loss Watts	10531.0512
*SR Loss Vars	3566880.00
*SR % Watt Cu Losses	-0.040629
*SR % Vars Cu Losses	-13.761111

<u>% Transformer Losses</u>		**<u>% Transmission Line Losses</u>**		**% Series Reactor Losses**		**<u>% Total Losses</u>**	
% Xfmr Watt Fe Loss	0.07774					%Tot. Watt Fe Loss	0.07774
% Xfmr Watt Cu Loss	1.01857	% Line Watt Cu Loss	1.02835	SR % Watt Cu Losses	-0.040629	%Tot. Watt Cu Loss	2.00063
% Xfmr VAr Fe Loss	0.15645					%Tot. VAr Fe Loss	0.15645
% Xfmr VAr Cu Loss	21.01307			SR % Var Cu Losses	-13.761111	%Tot. VAr Cu Loss	7.251959

<u>*Calculated Values for the Transformer, Series Reactor and Line Loss Compensation Calculation Sheet</u>	
Where:	Xfmr Sec. test amps=(Xfmr rating in VA)/(Xfmr secondary test p-p volt x Sqrt 3)
	Xfmr Pri. Amp @ 1/2Mtr CL=(Xfmr Secondary test p-p volt/Xfmr Primary test p-p volt) x Nominal CT Primary Amp
	Total Line Res.=Line Length x Line Res. (per mile)
	Line Loss=3 x Total Line Res. x (Xfmr Primary Amp @ 1/2 Meter Class amp)^2
	Average Series Reactor (SR) Resistance (3 Element)=(Phase A Reactor Resistance + Phase B Reactor Resistance + Phase C Reactor Resistance)/3
	Average Series Reactor (SR) Resistance (2 Element)=(Phase A Reactor Resistance + Phase C Reactor Resistance)/2
	Average Series Reactor (SR) Reactance (3 Element)=(Phase A Reactor Reactance + Phase B Reactor Reactance + Phase C Reactor Reactance)/3
	Average Series Reactor (SR) Reactance (2 Element)=(Phase A Reactor Reactance + Phase C Reactor Reactance)/2
	SR Loss Watts=((Nominal CT Primary Amps)^2)*Average SR Resistance
	SR Loss Vars=((Nominal CT Primary Amps)^2)*Average SR Reactance
	Meter Test Current=(Number of Elements * 1/2 Class Amps of Meter)
	SR % Watt Cu Losses= -(SR Loss Watts * 100)/(CTR*PTR*Meter Test Current*Meter Rated Volt)
	SR % Var Cu Losses= -(SR Loss Vars * 100)/(CTR*PTR*Meter Test Current*Meter Rated Volt)
	Meter Nominal Watts=(Meter Class amp/2) x Meter Rated voltage x Number of elements
	Nominal CT Primary Amps=(Meter Class amp/2) x CTR
	Meter secondary test Volt=(Xfmr sec test volt)/(PTR x Sqrt 3) for 3 elm; (Xfmr sec test volt)/(PTR) for 2 elm
	Nominal Primary VA=CTR x PTR x Meter Nominal Watts
	No Load VA loss=(Xfmr Excitation current x Xfmr rating in VA) / 100
	No Load loss phase angle=acos(Xfmr No Load watts loss/No Load VA loss)
	No Load VAr Loss=No Load VA loss x sin(No Load loss phase angle (alpha))
	Load VA loss=(Xfmr Impedance x Xfmr rating in VA) / 100
	Load loss ph angle (beta)=acos(Xfmr load loss/Load VA loss)
	Load VAr loss=Load VA loss x sin(Load loss phase angle (beta)
	% Watt Fe Loss=((Xfmr No-load loss x (Meter rated volt/Meter sec. test volt)^2) / Nominal Primary VA) x 100
	% Watt Cu Loss=((Xfmr Load loss x ((Meter Class amp/2) x (CTR/Xfmr sec. test amp))^2) / Nominal Primary VA) x 100

	% VAr Fe Loss=((No Load VAr loss x (Meter Rated volt/Meter Sec. test volt)^4) / Nominal Primary VA) x 100
	% VAr Cu Loss=((Load VAr loss x ((Meter Class amp/2) x (CTR/Xfmr sec. test amp))^2) / Nominal Primary VA) x 100
	% Line Cu Loss=(Line Loss VA/ Nominal Primary VA) x 100
	% Total Losses= %Xfmr(Fe or Cu) losses + %Line(Fe or Cu) losses

Percent Error Calculations for Meters		
With Transformer/Line Loss Compensation		
FL = 120 VOLTS @ 5 AMPS @ UNITY	**FL=**	**1.179**
LL = 120 VOLTS @ .5 AMPS @ UNITY	**LL=**	**1.657**
PF = 120 VOLTS @ 5 AMPS @ 50%	**PF=**	**2.358**
Calculations for Watt Loss Compensation		
FL = 1/2 Watt CU losses + 2 * Watt FE losses		
LL = 1/20th Watt CU losses + 20 * Watt FE losses		
PF = UNITY * 2		

ERCOT Settlement Metering Operating Guide

Section 9: Data Validation, Estimation and Editing Procedures

January 1, 2017

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9 DATA VALIDATION, ESTIMATION AND EDITING PROCEDURES

9.1 ERCOT Validation Process

(1) Refer to Protocol Section 11**,** Data Acquisition and Aggregation**,** for the ERCOT validation process.

9.2 ERCOT Editing and Estimation Process

(1) In the event ERCOT cannot communicate with the primary and back-up ERCOT-Polled Settlement (EPS) Meters through the normal communications path, either of the following should be utilized if possible:

(a) Temporary alternate communications (cell phone, microwave, satellite, and any other ERCOT Meter Data Acquisition System (MDAS)-compatible communications); or

(b) Compatible ERCOT MDAS formats (MV-90 “p” files, HandHeld File Format (HHF), etc.).

(2) Once it has been determined that data cannot be retrieved from the EPS Meters, ERCOT will perform an estimate utilizing the best available data and sound engineering practices. The following are examples of data that may be used:

(a) Non-EPS Meter data; and

(b) Supervisory Control and Data Acquisition (SCADA) data in conjunction with data provided by the Resource Entity.

9.2.1 Examples

(1) **Blown current transformer**: It was determined that data gathered from a metering point was incorrect due to a failure of a current transformer. This means that the data retrieved by the ERCOT MDAS is understating the actual quantity generated/consumed at the metering point. ERCOT determines from test reports that the energy flow is typically balanced across all phases. Since the meter is only recording data based on two working current transformers, the data would be increased by a factor of 1.5 (metered value is 66% of actual) to adjust for the current transformer failure.

Example: Actual generation value equals: 30 MWh.
Actual metered value equals: 30 MWh * 0.66666666 = 20 MWh
Estimated value equals: 20 MWh * 1.5 = 30 MWh

(2) **Determine un-metered generation using meter data**: A generation site consisting of three units has an EPS Meter installed on each unit. For one of the units, the primary and backup meters are destroyed due to lightning. ERCOT determines that another non-EPS

Meter is available for the whole site (i.e., the meter includes all the generation from the three units). To determine an estimate of the missing unit's generation, ERCOT would take the non-revenue quality total site meter and subtract the two EPS Meter values from the two other generation units.

(3) **Determine un-metered generation using SCADA data**: A site consisting of three generation units has EPS Meters installed at the transmission point of interconnect. The primary and backup meters are destroyed due to lightning. The SCADA signals from all three units were unaffected. ERCOT will retrieve and sum the signals for a like period when EPS Meter data was available. ERCOT will then perform a comparison analysis to compute an adjustment factor that will be applied to the SCADA data.

Example: SCADA signal for like period per unit is 10 MWh.
Total for the three units is 30 MWh.
Actual metered value for like period equals 26 MWh
Adjustment factor equals 26/30 = .866667
SCADA signal for estimate period equals 35MWh
Estimated value equals: .866667 * 35 = 30.333333

ERCOT Settlement Metering Operating Guide

Section 10: Process for Settlement Metering Operating Guide Revisions

January 1, 2024

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10 PROCESS FOR SETTLEMENT METERING OPERATING GUIDE REVISIONS

10.1 Introduction

(1) A request to make additions, edits, deletions, revisions, or clarifications to this Settlement Metering Operating Guide (SMOG), including any attachments and exhibits to this SMOG, is called a Settlement Metering Operating Guide Revision Request (SMOGRR). Except as specifically provided in other sections of this SMOG, this Section 10, Process for Settlement Metering Operating Guide Revisions, shall be followed for all SMOGRRs. ERCOT Members, Market Participants, Public Utility Commission of Texas (PUCT) Staff, the Reliability Monitor, the Independent Market Monitor (IMM), the North American Electric Reliability Corporation (NERC) Regional Entity, ERCOT, and any other Entities are required to utilize the process described herein prior to requesting, through the PUCT or other Governmental Authority, that ERCOT make a change to this SMOG, except for good cause shown to the PUCT or other Governmental Authority.

(2) The "next regularly scheduled meeting" of the Wholesale Market Subcommittee (WMS), the Technical Advisory Committee (TAC), the ERCOT Board, or the PUCT, shall mean the next regularly scheduled meeting for which required Notice can be timely given regarding the item(s) to be addressed, as specified in the appropriate PUCT, ERCOT Board, or committee procedures.

(3) WMS shall ensure that the SMOG is compliant with the ERCOT Protocols. As such, WMS will monitor all changes to the ERCOT Protocols and initiate any SMOGRRs necessary to bring the SMOG in conformance with the ERCOT Protocols. WMS will also initiate a Nodal Protocol Revision Request (NPRR) if such a change is necessary to accommodate a proposed SMOGRR prior to proceeding with that SMOGRR.

(4) Throughout the SMOG references are made to the ERCOT Protocols. ERCOT Protocols supersede the SMOG and any SMOGRRs must be compliant with the ERCOT Protocols. The ERCOT Protocols are subject to the revision process outlined in Protocol Section 21, Revision Request Process.

(5) ERCOT may make non-substantive corrections at any time during the processing of a particular SMOGRR. Under certain circumstances, however, the SMOG can also be revised by ERCOT rather than using the SMOGRR process outlined in this Section.

(a) This type of revision is referred to as an "Administrative SMOGRR" or "Administrative Changes" and shall consist of non-substantive corrections, such as typos (excluding grammatical changes), internal references (including table of contents), improper use of acronyms, references to ERCOT Protocols, PUCT Substantive Rules, the Public Utility Regulatory Act (PURA), NERC regulations, Federal Energy Regulatory Commission (FERC) rules, etc., and revisions for the purpose of maintaining consistency between Section 10 and Protocol Section 21.

(b) ERCOT shall post such Administrative SMOGRRs on the ERCOT website and distribute the SMOGRR to WMS. If no Entity submits comments to the Administrative SMOGRR within ten Business Days in accordance with paragraph (1) of Section 10.3.3, Wholesale Market Subcommittee Review and Action, the Administrative SMOGRR shall be subject to PUCT approval. Following PUCT approval, ERCOT shall implement the Administrative SMOGRR according to paragraph (3) of Section 10.6, Settlement Metering Operating Guide Revision Implementation. If any Entity submits comments to the Administrative SMOGRR, then it shall be processed in accordance with the SMOGRR process outlined in this Section 10.

10.2 Submission of a Settlement Metering Operating Guide Revision Request

(1) The following Entities may submit a Settlement Metering Operating Guide Revision Request (SMOGRR):

(a) Any Market Participant;

(b) Any ERCOT Member;

(c) Public Utility Commission of Texas (PUCT) Staff;

(d) The Reliability Monitor;

(e) The North American Electric Reliability Corporation (NERC) Regional Entity;

(f) The Independent Market Monitor (IMM);

(g) ERCOT; and

(h) Any other Entity that meets the following qualifications:

(i) Resides (or represents residents) in Texas or operates in the Texas electricity market; and

(ii) Demonstrates that Entity (or those it represents) is affected by the Customer Registration or Renewable Energy Credit (REC) Trading Program sections of the ERCOT Protocols.

10.3 Settlement Metering Operating Guide Revision Procedure

10.3.1 Review and Posting of Settlement Metering Operating Guide Revision Requests

(1) Settlement Metering Operating Guide (SMOG) Revision Requests (SMOGRRs) shall be submitted electronically to ERCOT by completing the designated form provided on the

ERCOT website. Excluding ERCOT-sponsored SMOGRRs, ERCOT shall provide an electronic return receipt response to the submitter upon receipt of the SMOGRR.

(2) The SMOGRR shall include the following information:

(a) Description of requested revision and reason for suggested change;

(b) Impacts and benefits of the suggested change on ERCOT market structure, ERCOT operations, and Market Participants, to the extent that the submitter may know this information;

(c) List of affected SMOG sections and subsections;

(d) General administrative information (organization, contact name, etc.); and

(e) Suggested language for requested revision.

(3) ERCOT shall evaluate the SMOGRR for completeness and shall notify the submitter, within five Business Days of receipt, if the SMOGRR is incomplete, including the reasons for such status. ERCOT may provide information to the submitter that will correct the SMOGRR and render it complete. An incomplete SMOGRR shall not receive further consideration until it is completed. In order to pursue the SMOGRR, a submitter must submit a completed version of the SMOGRR.

(4) If a submitted SMOGRR is complete or upon completion of a SMOGRR, ERCOT shall post the SMOGRR on the ERCOT website and distribute to the Wholesale Market Subcommittee (WMS) within three Business Days.

(5) For any ERCOT-sponsored SMOGRR, ERCOT shall also post an initial Impact Analysis on the ERCOT website, and distribute it to WMS. The initial Impact Analysis will provide WMS with guidance as to potential ERCOT computer systems, operations, or business functions that could be affected by the submitted SMOGRR.

10.3.2 Withdrawal of a Settlement Metering Operating Guide Revision Request

(1) A submitter may withdraw or request to withdraw a SMOGRR by submitting a completed Request for Withdrawal form provided on the ERCOT website. ERCOT shall post the submitter's Request for Withdrawal on the ERCOT website within three Business Days of submittal.

(2) The submitter of a SMOGRR may withdraw the SMOGRR at any time before WMS recommends approval of the SMOGRR.

(3) If WMS has recommended approval of the SMOGRR, the Request for Withdrawal must be approved by the Technical Advisory Committee (TAC) if the SMOGRR has not yet been recommended for approval by TAC.

(4) If TAC has recommended approval of a SMOGRR, the Request for Withdrawal must be approved by the ERCOT Board if the SMOGRR has not yet been recommended for approval by the ERCOT Board.

(5) Once recommended for approval by the ERCOT Board, a SMOGRR cannot be withdrawn.

10.3.3 Wholesale Market Subcommittee Review and Action

(1) Any ERCOT Member, Market Participant, Public Utility Commission of Texas (PUCT) Staff, the Reliability Monitor, the North American Electric Reliability Corporation (NERC) Regional Entity, the Independent Market Monitor (IMM), or ERCOT may comment on the SMOGRR.

(2) To receive consideration, comments must be delivered electronically to ERCOT in the designated format provided on the ERCOT website within 14 days from the posting date of the SMOGRR. Comments submitted after the 14 day comment period may be considered at the discretion of WMS after these comments have been posted. Comments submitted in accordance with the instructions on the ERCOT website, regardless of date of submission, shall be posted on the ERCOT website and distributed to the WMS within three Business Days of submittal.

(3) WMS shall consider the SMOGRR at its next scheduled meeting after the end of the 14 day comment period. The quorum and voting requirements for WMS action are set forth in the Technical Advisory Committee Procedures. At such meeting, WMS shall take action on the SMOGRR. In considering action on a SMOGRR, WMS shall:

(a) Recommend approval of the SMOGRR as submitted or as modified;

(b) Reject the SMOGRR;

(c) Table the SMOGRR; or

(d) Refer the SMOGRR to another WMS working group or task force, or another TAC subcommittee with instructions.

(4) If a motion is made to recommend approval of a SMOGRR and that motion fails, the SMOGRR shall be deemed rejected by WMS unless at the same meeting WMS later votes to recommend approval of, table, or refer the SMOGRR. If a motion to recommend approval of a SMOGRR fails via e-mail vote according to the Technical Advisory Committee Procedures, the SMOGRR shall be deemed rejected by WMS unless at the next regularly scheduled WMS meeting or in a subsequent e-mail vote prior to such meeting, WMS votes to recommend approval of, table, or refer the SMOGRR. The rejected SMOGRR shall be subject to appeal pursuant to Section 10.4, Appeal of Action.

(5) Within three Business Days after WMS takes action, ERCOT shall post a WMS Report reflecting the WMS action on the ERCOT website. The WMS Report shall contain the following items:

(a) Identification of submitter of the SMOGRR;

(b) SMOG language recommended by WMS, if applicable;

(c) Identification of authorship of comments;

(d) Proposed effective date(s) of the SMOGRR;

(e) Recommended priority and rank for any SMOGRRs requiring an ERCOT project for implementation; and

(f) WMS action.

(6) The WMS chair shall notify TAC of Revision Requests rejected by WMS.

10.3.4 Comments to the Wholesale Market Subcommittee Report

(1) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the NERC Regional Entity, the IMM, or ERCOT may comment on the WMS Report. Comments submitted in accordance with the instructions on the ERCOT website, regardless of date of submission, shall be posted on the ERCOT website and distributed to the committee (i.e., WMS and/or TAC) considering the SMOGRR within three Business Days of submittal.

(2) The comments on the WMS Report will be considered at the next regularly scheduled WMS or TAC meeting where the SMOGRR is being considered.

10.3.5 Settlement Metering Operating Guide Revision Request Impact Analysis

(1) If WMS recommends approval of a SMOGRR, ERCOT shall prepare an Impact Analysis based on the proposed language in the WMS Report. If ERCOT has already prepared an Impact Analysis, ERCOT shall update the existing Impact Analysis, if necessary, to accommodate the language recommended for approval in the WMS Report.

(2) The Impact Analysis shall assess the impact of the proposed SMOGRR on ERCOT staffing, computer systems, operations, or business functions and shall contain the following information:

(a) An estimate of any cost and budgetary impacts to ERCOT for both implementation and ongoing operations;

(b) The estimated amount of time required to implement the SMOGRR;

(c) The identification of alternatives to the SMOGRR that may result in more efficient implementation; and

(d) The identification of any manual workarounds that may be used as an interim solution and estimated costs of the workaround.

(3) Unless a longer review period is warranted due to the complexity of the proposed WMS Report, ERCOT shall post an Impact Analysis on the ERCOT website, for a SMOGRR for which WMS has recommended approval of, prior to the next regularly scheduled WMS meeting, and distribute to WMS. If a longer review period is required by ERCOT to complete an Impact Analysis, ERCOT shall submit comments with a schedule for completion of the Impact Analysis.

10.3.6 Wholesale Market Subcommittee Review of Impact Analysis

(1) After ERCOT posts the results of the Impact Analysis, WMS shall review the Impact Analysis at its next regularly scheduled meeting. WMS may revise its WMS Report after considering the information included in the Impact Analysis or additional comments received on the WMS Report.

(2) Within three Business Days of WMS consideration of the Impact Analysis and WMS Report, ERCOT shall post the WMS Report on the ERCOT website. If WMS revises the WMS Report, ERCOT shall update the Impact Analysis, if necessary, post the updated Impact Analysis on the ERCOT website, and distribute it to the committee (i.e., WMS and/or TAC) considering the Impact Analysis. If a longer review period is required for ERCOT to update the Impact Analysis, ERCOT shall submit comments with a schedule for completion of the Impact Analysis.

(3) If the SMOGRR requires an ERCOT project for implementation, at the same meeting, WMS shall assign a recommended priority and rank for the associated project.

10.3.7 ERCOT Impact Analysis Based on Wholesale Market Subcommittee Report

(1) ERCOT shall review the WMS Report and, if necessary, update the Impact Analysis as soon as practicable. ERCOT shall distribute the updated Impact Analysis, if applicable, to TAC and post it on the ERCOT website. If a longer review period is required for ERCOT to update the Impact Analysis, ERCOT shall submit comments with a schedule for completion of the Impact Analysis.

10.3.8 PRS Review of Project Prioritization

(1) At the next regularly scheduled Protocol Revision Subcommittee (PRS) meeting after WMS recommends approval of a SMOGRR that requires an ERCOT project for implementation, the PRS shall assign a recommended priority and rank for the associated project.

10.3.9 Technical Advisory Committee Vote

(1) TAC shall consider any SMOGRR that WMS has submitted to TAC for consideration for which both a WMS Report and an Impact Analysis (as updated if modified by WMS under Section 10.3.7, ERCOT Impact Analysis Based on Wholesale Market Subcommittee Report) have been posted on the ERCOT website. The following information must be included for each SMOGRR considered by TAC:

(a) The WMS Report and Impact Analysis;

(b) The WMS-recommended priority and rank, if an ERCOT project is required; and

(c) Any comments timely received in response to the WMS Report.

(2) The quorum and voting requirements for TAC action are set forth in the Technical Advisory Committee Procedures. In considering action on a WMS Report, TAC shall:

(a) Recommend approval of the SMOGRR as recommended in the WMS Report or as modified by TAC;

(b) Reject the SMOGRR;

(c) Table the SMOGRR;

(d) Remand the SMOGRR to WMS with instructions; or

(e) Refer the SMOGRR to another TAC subcommittee or a TAC working group or task force with instructions.

(3) If a motion is made to recommend approval of a SMOGRR and that motion fails, the SMOGRR shall be deemed rejected by TAC unless at the same meeting TAC later votes to recommend approval of, table, remand, or refer the SMOGRR. If a motion to recommend approval of a SMOGRR fails via e-mail vote according to the Technical Advisory Committee Procedures, the SMOGRR shall be deemed rejected by TAC unless at the next regularly scheduled TAC meeting or in a subsequent e-mail vote prior to such meeting, TAC votes to recommend approval of, table, remand, or refer the SMOGRR. The rejected SMOGRR shall be subject to appeal pursuant to Section 10.4, Appeal of Action.

(4) Within three Business Days after TAC takes action on a SMOGRR, ERCOT shall post a TAC Report reflecting the TAC action on the ERCOT website. The TAC Report shall contain the following items:

(a) Identification of the submitter of the SMOGRR;

(b) Modified SMOG language proposed by TAC, if applicable;

(c) Identification of the authorship of comments, if applicable;

(d) Proposed effective date(s) of the SMOGRR;

(e) Priority and rank for any SMOGRR requiring an ERCOT project for implementation;

(f) WMS action;

(g) TAC action;

(h) IMM Opinion;

(i) ERCOT Opinion; and

(j) ERCOT Market Impact Statement.

(5) If TAC recommends approval of a SMOGRR, ERCOT shall forward the TAC Report to the ERCOT Board for consideration pursuant to Section 10.3.10, ERCOT Board Vote.

(6) The TAC chair shall report the results of all votes by TAC related to SMOGRRs to the ERCOT Board at its next regularly scheduled meeting.

10.3.10 ERCOT Board Vote

(1) Upon issuance of a TAC Report and Impact Analysis to the ERCOT Board, the ERCOT Board shall review the TAC Report and the Impact Analysis at the next regularly scheduled meeting. For Urgent SMOGRRs, the ERCOT Board shall review the TAC Report and Impact Analysis at the next regularly scheduled meeting, unless a special meeting is required due to the urgency of the SMOGRR.

(2) The quorum and voting requirements for ERCOT Board action are set forth in the ERCOT Bylaws. In considering action on a TAC Report, the ERCOT Board shall:

(a) Recommend approval of the SMOGRR as recommended in the TAC Report or as modified by the ERCOT Board;

(b) Reject the SMOGRR;

(c) Table the SMOGRR; or

(d) Remand the SMOGRR to TAC with instructions.

(3) If a motion is made to recommend approval of a SMOGRR and that motion fails, the SMOGRR shall be deemed rejected by the ERCOT Board unless at the same meeting the ERCOT Board later votes to recommend approval of, table, or remand the SMOGRR. The rejected SMOGRR shall be subject to appeal pursuant to Section 10.4, Appeal of Action.

(4) Within three Business Days after the ERCOT Board takes action on a SMOGRR, ERCOT shall post a Board Report reflecting the ERCOT Board action on the ERCOT website.

10.3.11 PUCT Approval of Revision Requests

(1) All SMOGRRs require approval by the PUCT prior to implementation.

(2) Within three Business Days after the PUCT takes action on a SMOGRR, ERCOT shall post a PUCT Report reflecting the PUCT action on the ERCOT website.

10.4 Appeal of Action

(1) Any ERCOT Member, Market Participant, Public Utility Commission of Texas (PUCT) Staff, the Reliability Monitor, the Independent Market Monitor (IMM), the North American Electric Reliability Corporation (NERC) Regional Entity or ERCOT may appeal a Wholesale Market Subcommittee (WMS) action to reject, table, or refer a Settlement Metering Operating Guide Revision Request (SMOGRR) directly to the Technical Advisory Committee (TAC). Such appeal to the TAC must be submitted electronically to ERCOT by completing the designated form provided on the ERCOT website within seven days after the date of the relevant WMS appealable event. ERCOT shall reject appeals made after that time. ERCOT shall post appeals on the ERCOT website within three Business Days of receiving the appeal. Appeals shall be heard at the next regularly scheduled TAC meeting that is at least seven days after the date of the requested appeal. An appeal of a SMOGRR to TAC suspends consideration of the SMOGRR until the appeal has been decided by TAC.

(2) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the IMM, the NERC Regional Entity, or ERCOT may appeal a TAC action to reject, table, remand or refer a SMOGRR directly to the ERCOT Board. Appeals to the ERCOT Board shall be processed in accordance with the ERCOT Board Policies and Procedures. An appeal of a SMOGRR to the ERCOT Board suspends consideration of the SMOGRR until the appeal has been decided by the ERCOT Board.

(3) Any ERCOT Member, Market Participant, PUCT Staff or the Reliability Monitor, the IMM, or the NERC Regional Entity may appeal any decision of the ERCOT Board regarding a SMOGRR to the PUCT or other Governmental Authority. Such appeal to the PUCT or other Governmental Authority must be made within any deadline prescribed by the PUCT or other Governmental Authority, but in any event no later than 35 days of the date of the relevant ERCOT Board appealable event. Notice of any appeal to the PUCT or other Governmental Authority must be provided, at the time of the appeal, to ERCOT's General Counsel. If the PUCT or other Governmental Authority rules on the SMOGRR, ERCOT shall post the ruling on the ERCOT website.

10.5 Urgent Requests

(1) The party submitting a Settlement Metering Operating Guide (SMOG) Revision Request (SMOGRR) may request that the SMOGRR be considered on an urgent timeline ("Urgent") only when the submitter can reasonably show that an existing SMOG provision is impairing or could imminently impair ERCOT System reliability or wholesale or retail market operations, or is causing or could imminently cause a discrepancy between a Settlement formula and a provision of the ERCOT Protocols.

(2) The Wholesale Market Subcommittee (WMS) may designate the SMOGRR for Urgent consideration if a submitter requests Urgent status or upon valid motion in a regularly scheduled meeting of WMS. Criteria for designating a SMOGRR as Urgent are that the SMOGRR requires immediate attention due to:

(a) Serious concerns about ERCOT System reliability or market operations under the unmodified language; or

(b) The crucial nature of Settlement activity conducted pursuant to any Settlement formula.

(3) ERCOT shall prepare an Impact Analysis for Urgent SMOGRRs as soon as practicable.

(4) WMS shall consider the Urgent SMOGRR and Impact Analysis, if available, at the next regularly scheduled WMS meeting, or at a special meeting called by WMS leadership to consider the Urgent SMOGRR.

(5) If the submitter desires to further expedite processing of the SMOGRR, a request for voting via e-mail may be submitted to the WMS chair. The WMS chair may grant the request for voting via e-mail. Such voting shall be conducted pursuant to the Technical Advisory Committee Procedures.

(6) If recommended for approval by WMS, ERCOT shall post a WMS Report on the ERCOT website within three Business Days after WMS takes action. The Technical Advisory Committee (TAC) chair may request action from TAC to accelerate or alter the procedures described herein, as needed, to address the urgency of the situation.

(7) Any Urgent SMOGRRs shall be subject to an Impact Analysis pursuant to Section 10.3.7, ERCOT Impact Analysis Based on Wholesale Market Subcommittee Report, and TAC consideration pursuant to Section 10.3.9, Technical Advisory Committee Vote.

10.6 Settlement Metering Operating Guide Revision Implementation

(1) Following Public Utility Commission of Texas (PUCT) approval, ERCOT shall implement Settlement Metering Operating Guide Revision Requests (SMOGRRs) on the first day of the month following PUCT approval, unless otherwise provided in the PUCT Report for the approved SMOGRR.

(2) For such other SMOGRRs, the Impact Analysis shall provide an estimated amount of time required to implement the SMOGRR and ERCOT shall issue a Market Notice as soon as practicable, but no later than ten days prior to the actual implementation, unless a different notice period is required in the PUCT Report for the approved SMOGRR.

(3) ERCOT shall implement an Administrative SMOGRR on the first day of the month following PUCT approval.

ERCOT Settlement Metering Operating Guide
Section 11
Appendix A

Documentation Requirements after Access to EPS Metering Facilities
Settlement Metering Process - 030

March 1, 2021

Appendix A
Documentation Requirements after Access to EPS Metering Facilities
Settlement Metering Process - 030

Immediate Information Requirements After Site Access

The Transmission and/or Distribution Service Provider (TDSP) or Resource Entity must communicate closely with ERCOT, during access periods to ERCOT-Polled Settlement (EPS) Metering Facilities, to ensure accurate data is available for Initial Settlement. Initial information submitted by the TDSP/Resource Entity to ERCOT must be provided in sufficient detail and in a timeframe to support Initial Settlement.

Such information shall be conveyed using voice communications to ERCOT Meter Data Acquisition System (MDAS) (512-248-6500) at the conclusion of the access period, with a follow-up e-mail sent to mreads@ercot.com and TDSP.

Minimum information required following site access:

- Site name "as specified on the approved EPS Metering Design Proposal."
- Meter serial number.
- Date and time period access occurred; including the time the metering was out of service.
- Description of the performed work during such access period.
- The source the Settlement data will be available for such access period.
- Information on the affects the access or reason for the access had on metering accuracy and meter data, including any time frames that accuracy or data was affected.
- If meter data is missing for any Settlement Intervals, the TDSP will assist ERCOT in the edit of meter data for such site.

Interval data requirements to support Initial Settlement after site access:

- If the EPS Meter site has a primary and backup meter already on location and the required access can be made without affecting the data in both meters during the same Settlement Interval, ERCOT will be able to use the data from one or the other meters to fill in any missing data as a result of this change.
- In situations where meter data for the primary and backup is affected for the same interval or there is not a certified backup meter, the TDSP shall provide other information and data to assist ERCOT in performing edits or estimation for

missing intervals of meter data. Such information or data should be available by close of business the business day following access to EPS Metering Facilities. ERCOT will perform the edit with the assistance of the TDSP, so that reasonable data is available for Initial Settlement.

TDSP Documentation Submission Requirements After Site Access

Any access to approved EPS Metering Facilities shall be documented by the TDSP with such documentation submitted to ERCOT. The required timeframe for submittal of such documentation shall be dependent on the exact nature of the performed work and the implications such work has on Initial Settlement. The following list of events, though not inclusive, is provided to assist the TDSP in understanding the type of documentation required after access to any approved EPS Metering Facility. Other documentation may be required depending on the nature of the performed work:

- EPS Meter Test (no changes to the meter):
    - EPS Meter Test Report.
- EPS Meter reprogramming that downloads “meter configuration files”:
    - EPS Meter Test Report.
    - MDAS Configuration Form.
    - Pulse Multiplier Calculation Sheet (if changed).
    - Meter Multiplier Calculation Sheet (if changed).
    - EPS Meter Program details in a text file format as downloaded from the certified meter.
- EPS Meter reprogramming that uses a specific command to set a specific parameter in the meter that is not used in the calculation of energy or does not map the storage of Settlement data in the meter:
    - Confirmation that the explanation of the planned work on the “notification e-mail” was the actual work performed.
    - E-mail confirmation of the date and time period the maintenance was performed.
    - Confirmation statement that the meter program was not altered, except as specifically documented in the actual work performed.
- EPS Meter replacements:
    - EPS Meter Test Report.

  - MDAS Configuration Form.
  - EPS Site Certification Form.
  - Pulse Multiplier Calculation Sheet (if changed).
  - Meter Multiplier Calculation Sheet (if changed).
  - EPS Meter Program details in a text file format as downloaded from the certified meter.

- EPS instrument transformer replacements:
  - EPS Metering Design Proposal (if changed).
  - EPS Meter Test Report.
  - EPS Site Certification Form.
  - MDAS Configuration Form (if changed).
  - Pulse Multiplier Calculation Sheet (if changed).
  - Meter Multiplier Calculation Sheet (if changed).
  - Certification of instrument transformers by the TDSP.

- Removal of any Facility wiring for site certification or site testing purposes:
  - EPS Site Certification Form.

- Communication failure that is external to the EPS Meter:
  - Provide either voice communications to the MDAS Group or e-mail confirmation of repairs to ERCOT at mreads@ercot.com, including the following information:
    - Site name.
    - Meter serial number.
    - Date and time period the repair was performed.
    - Explanation of the performed repairs.

- Maintenance to non-EPS metering equipment that is connected to the EPS metering circuit. (Testing or programming that does not require the removal of EPS Meter seals):

Note: The testing of this equipment must not interfere with the accuracy of the energy measured and recorded by the EPS meter while such equipment is being tested.

- o Confirmation that the explanation of the planned work on the "notification e-mail" was the actual work performed.
- o E-mail confirmation of the date and time period the maintenance was performed.

- Replacement, removal or addition of non-EPS Metering equipment that is connected to the EPS Metering circuit:
  - o Explanation of the planned work on the "notification e-mail."
  - o Confirmation of the date and time period the maintenance was performed.
  - o EPS Meter Site Certification Form.

Resource Entity Documentation Submission Requirements After Site Access

Any access to approved auxiliary Load telemetry system shall be documented by the Resource Entity with such documentation submitted to ERCOT and the TDSP. The required timeframe for submittal of such documentation shall be dependent on the exact nature of the performed work and the implications such work has on Initial Settlement. The following list of events, though not inclusive, is provided to assist the Resource Entity in understanding the type of documentation required after access to any approved auxiliary Load telemetry system. Other documentation may be required depending on the nature of the performed work:

- Replacement, repair, removal, addition, reprogramming or reconfiguration of any equipment that results in changes to the calculation of the auxiliary Load telemetry provided to the EPS Meter.
  - o Resource Entity Auxiliary Load Calculation Attestation Form (Section 11, Appendix D, Resource Entity Attestation for Calculation and Telemetry of Energy Storage Resource (ESR) Auxiliary Load Values)
- Replacement, repair, removal, addition, reprogramming or reconfiguration of any equipment that does not result in changes to the calculation of the auxiliary Load telemetry provided to the EPS Meter.
  - o Confirmation that the explanation of the planned work on the "notification e-mail" was the actual work performed.
  - o E-mail confirmation of the date and time period the maintenance was performed.

ERCOT Settlement Metering Operating Guide
Section 11
Appendix B

On Site Work to EPS Metering Facilities
Settlement Metering Process - 020

March 1, 2021

Appendix B
On Site Work to EPS Metering Facilities
Settlement Metering Process - 020

Notification of Required Access to EPS Metering Facilities

- For maintenance or changes to ERCOT-Polled Settlement (EPS) Metering Facilities, the Transmission and/or Distribution Service Provider (TDSP) shall notify ERCOT when access is expected to occur by completing the "TDSP Access to EPS Metering Facility Notification Form" and e-mailing the completed form to "mreads@ercot.com":
    - The e-mail subject line shall read "EPS Access Required – SITE NAME."
- For maintenance or changes to equipment used in the calculation of the auxiliary Load telemetry provided to an EPS Meter, the Resource Entity shall notify ERCOT and the TDSP when access is expected to occur by completing the "Resource Entity Access to Auxiliary Load Telemetry System Notification Form" and e-mailing the completed form to mreads@ercot.com and an email contact provided to the Resource Entity by the TDSP:
    - The e-mail subject line shall read "Telemetry Access required – SITE NAME"
- For "emergency repairs," the TDSP can notify ERCOT of the need to access EPS Metering Facilities by calling the Meter Data Acquisition System (MDAS) Operations Center at 512-248-6500 and submit the "TDSP Access to EPS Metering Facility Notification Form" by the end of the next Business Day following such access.
- For "emergency repairs" of equipment used in the calculation of the auxiliary Load telemetry provided to an EPS Meter, the Resource Entity can notify ERCOT of the need to access EPS Metering Facilities by calling the Meter Data Acquisition System (MDAS) Operations Center at 512-248-6500 and submit the "Resource Entity Access to Auxiliary Load Telemetry System Notification Form" by the end of the next Business Day following such access.

Examples of Maintenance Included in the Five Business Day Notification Period

- EPS Meter maintenance.
- Removal of any EPS Metering Facility wiring.
- Maintenance to non-EPS Metering equipment that is connected to the EPS Metering circuit.

Examples of Changes Included in the Ten Business Day Notification Period

- EPS Metering equipment changes or replacements (non emergency).
- EPS Metering equipment reprogramming (non emergency).
- Upgrade the site from "temporary metering" to "permanent metering."
- Changes to equipment used in the calculation of the auxiliary Load telemetry provided to an EPS Meter (non-emergency).
- Planned modifications to the calculation of the auxiliary Load in the Resource Entity equipment as recorded on the "Resource Entity Access to Auxiliary Load Telemetry System Notification Form".

Examples of Repairs Included in the Immediate Notification Period

- This category is for unplanned work being performed to repair EPS Metering Facilities due to a failure.
    - Communication failure to an EPS Meter.
    - Meter reprogramming.
    - EPS Meter replacements.
    - EPS instrument transformer replacements.
    - Replacement or repair of equipment used in the calculation of the auxiliary Load telemetry provided to an EPS Meter.
    - Immediate modifications to prevent under reporting of the calculation of the auxiliary Load in the Resource Entity equipment as recorded on the "Resource Entity Access to Auxiliary Load Telemetry System Notification Form".

Planned Maintenance or Testing of Equipment

- The primary and the backup meters shall not be taken out of service during the same Settlement Interval (15-minute time interval), unless the scope of work requires both meters being out of service at the same time.
- Before removing an EPS meter from service, the TDSP EPS Meter Inspector shall:
    - Notify ERCOT that the meter shall be removed from service by calling ERCOT MDAS at (512) 248-6500. A voice mail message is considered adequate notification.

  - If there is not a certified backup meter, ensure that interval data is downloaded from the meter. Such meter download shall be in a format that allows the creation of an MDAS compatible file format (Example: HHF File, P-File, E-File, CSV file) for such data. This can be accomplished by:

    (a) ERCOT polling the meter.

    (b) The TDSP polling the meter.

    (c) The TDSP downloading the interval data.

- If the EPS meter is an ONLY meter or the changes/maintenance cannot be performed without pulling the primary and backup meter(s) out of service during the same 15-minute time interval.

    (a) The TDSP shall make arrangements to assist ERCOT in the estimation of meter data for the metering point before the meter is removed from service.

    (b) ERCOT will ask the TDSP to provide 15-minute interval data to be utilized to perform the edit in the ERCOT MDAS system.

    (c) If the TDSP determines that 15-minute interval data cannot be provided, ERCOT will perform the edit with the assistance of the TDSP so that reasonable data is available as per the Protocols for Settlement billing.

- ERCOT recommends that during normal business hours, the TDSP should request to have ERCOT poll the meters to see that they are back in proper working condition and perform a Load verification.

Repairs of Equipment

NOTE *** If the metering at an EPS Metering Facility is totally out of service, then changes/maintenance or repairs may be completed before ERCOT is notified. Once the EPS Meters are back in service, arrangements for the data to be provided or estimated will be handled at that time.

ERCOT Settlement Metering Operating Guide
Section 11
Appendix C

TDSP Notification by ERCOT of Communication Problems with EPS Meters
Settlement Metering Process - 000

May 1, 2014

Appendix C
TDSP Notification by ERCOT of Communication Problems with EPS Meters
Settlement Metering Process - 000

ERCOT shall:

- Manually reschedule calls to try and establish meter communications with failed locations.
- Identify if primary or backup meter data is available for the metering point.
- Determine the required time frame for repairs per the Protocols.
- Notify the Transmission and/or Distribution Service Provider (TDSP) repair contact via phone and e-mail as soon as reasonably possible. Note: the TDSP repair contact was established by the TDSP in response to an e-mail request from ERCOT. ERCOT may issue such a notification on a Business Day or on a Saturday where weekends and ERCOT holidays result in four consecutive days that are not Business Days. The target time frame for such a notification is 0900.
    - Notification shall include:
        - Site Name.
        - Meter serial number.
        - Required time frame for repairs
        - Brief description of the problem as experienced by ERCOT, including:
            - Rings, but no answer
            - Answers as out of service
            - Busy signal
            - Error messages
            - Other
- Issue a 12-hour or six-hour notice by phone and e-mail when both the primary and backup meter communications are down.
    - Six-hour notice, may be issued when:

        - ERCOT-Polled Settlement (EPS) Meter data for a given Operating Day will be used in the Real-Time Market (RTM) Settlement processes on:

            - The same day; or

            - An upcoming non-Business Day

- Send an escalation e-mail to the TDSP EPS metering escalation contact list, as defined by the TDSP EPS metering contact, if EPS Meter data has not been provided by 1500, for six-hour notices.

- Send a cancelation e-mail for any 12-hour or six-hour notice that has been issued if either of the following conditions are met:

    - Communications have been reestablished with both the primary and backup meters, or

    - A temporary exemption is approved that documents the communications issue and requests opting out of future notices until communications are restored.

- Issue a five Business Day notice by phone and e-mail when either the primary or backup meter communications are down.

- Provide reasonable support to the TDSP to verify the communication problem is resolved. To facilitate this support:

    - The TDSP must provide ERCOT an estimated time when such support is required for a site.

- Log a record of the phone and e-mail notification including the name of the phone contact:

    - Record the repair date and time reported by the TDSP to ERCOT.

TDSP shall:

- Make reasonable efforts to adhere to the repair timelines in the notices.

- Notify ERCOT by e-mail in instances where a repair cannot be accomplished in the designated timeframe.

- Provide communications to ERCOT on the repair timeline by phone or e-mail.

- For six-hour notices:

- Submit EPS Meter data or estimation instructions by e-mail covering the prior Operating Days to ERCOT by 1500 on the same day the six-hour notice is generated, and
- Submit meter data or estimation instructions by e-mail to ERCOT by 1500 on subsequent Mondays, Wednesdays, and Fridays until repairs are made and communications are reestablished.

- Respond to escalation e-mails in a timeframe that supports the provision of data for RTM Settlements.
- Provide confirmation of repairs to ERCOT by phone or e-mail including the following information:
    - Site name.
    - Meter serial number.
    - Date and time repairs were made.
    - Brief description of what was done to repair the communication problem.
    - Information on the affects the problem had on metering accuracy and meter data for the affected meter, including the time frames that such accuracy or data was affected.
- Provide an e-mail notification to ERCOT at mreads@ercot.com when requesting a change to the TDSP repair contact information:
    - A temporary change to the repair contact information shall be identified as such and shall include the beginning and ending date that such change is to be in effect.
        - The subject line should state “TDSP Name temporary change to TDSP repair contact.”
    - A “permanent” change to the repair contact information shall be identified as such and shall include the beginning date that such change shall take place:
        - The subject line should state “TDSP Name permanent change to TDSP repair contact.”

ERCOT Settlement Metering Operating Guide
Section 11
Appendix D

Resource Entity Attestation for Calculation and Telemetry of Energy Storage Resource (ESR) Auxiliary Load Values

March 1, 2021

Appendix D
Resource Entity Attestation for Calculation and Telemetry of Energy Storage Resource (ESR) Auxiliary Load Values

Attestation pursuant to Protocol Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values

Instructions: This form shall be submitted annually by the Resource Entity to epsmetering@ercot.com, per time requirement as detailed in paragraph (2) of Section 1.7.1, Test Records.

1. Section A: Resource Entity completion to affirm compliance of calculated auxiliary Load.
2. Section B: Resource Entity completion to confirm or update contact information.
3. Section C: Texas Professional Engineer annual completion confirms the auxiliary Load calculation does not understate the Load value.
    a. Part I: Texas PE information.
    b. Part II: Includes all supporting test results, records and any additional findings identified in the Texas PE audit.

Section A. Attestation.

I, ________________________, am an officer of ________________________ [Resource Entity] capable of attesting to the following facts regarding [ESR Project Company Name], applicable to the annual attestation period _______________ to _________________ (Applicable Period).

I hereby attest that the results of an independent audit performed by an independent registered Texas Professional Engineer (attached herein) demonstrate that testing has been conducted on the specified sensor models used at the site. In each interval during the Applicable Period, calculated and telemetered data accounted for any known sensor accuracy or degradation information such that the auxiliary Load calculation did not understate the Load value.

I hereby swear to the accuracy and completeness of these statements and affirm that [Resource Entity/Project] is in compliance with Protocol Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values, and the ERCOT approved Design Proposal, and that Resource Entity has reasonable controls in place to ensure the accuracy and integrity of the data provided as required by this Section and with any additional provisions enumerated in this Section.

Texas Notary Public Signature and Date ____

Resource Entity Officer Signature and Date ____

Section B: Resource Entity Information and Signature

Resource Entity Signing Manager Information and Signature			
Attesting Organization			
Printed Name		Title	
Signatory Email		Signatory Phone	
Additional Contact Name		Additional Contact Email	
Indicate if there is a Change in Contact Information for the Applicable Resource Entity			
Y______		N________	

Section C. Audit Information

Audit Facilitator Information	
Part I: Required	
Auditor Name:	
Auditor Firm:	
Texas PE License Number:	
Audit Date:	
Auditor Stamp and Signature:	

Attach laboratory results and additional documentation. Section C Part II may also be used to document additional audit findings.

Part II: Additional Self Audit Findings		
Please input "NA" for first row of fields if there are no incidents to report. If all findings do not fit the space provided, please contact <epsmetering@ercot.com> for further instructions on how to complete report.		
Findings	# of Incidents	Actions taken

Settlement Metering Operating Guide
Section 12
Attachment A

EPS Metering Design Proposal

May 1, 2024

PUBLIC

Purpose

The EPS Metering Design Proposal is the initial document required from a Transmission and/or Distribution Provider (TDSP) to obtain ERCOT approval of a proposed EPS Metering Facility design. The EPS metering design proposal includes general facility information, contact information, metering facility details, and a one line drawing showing an overview of the metering facility design. The Resource owner (if the design proposal is for a generation site) must agree with the design proposal submitted by the TDSP.

The following forms are provided to document the EPS metering design proposal with a description of each field in pages 8 through 13:

A. Facility Information and Contact Information (page 2)

B. Metering Facility Details (page 3 or 4). Add more pages if necessary. Utilize page 4 for parallel CTs and throw-over VT schemes. Complete one Section B for each metering point.

C. TDSP one line drawing (page 6)

D. Auxiliary Load Telemetry Details (page 7). Add more pages if necessary. Complete one Section D for each metering point that has an auxiliary load telemetered.

When completing the forms, please provide all requested information and use the comments section to provide any additional information to clarify the facility metering design. Please feel free to attach other documents that are needed to facilitate the understanding of the EPS Metering Design Proposal. Completed design proposals should be submitted to EPSMetering@ercot.com

<table>
<tr><th colspan="6">A. FACILITY INFORMATION AND CONTACT INFORMATION</th></tr>
<tr><td>1. Facility Name</td><td colspan="5"></td></tr>
<tr><td>2. Facility Address</td><td colspan="5"></td></tr>
<tr><td>3. TDSP</td><td colspan="2"></td><td colspan="2">7. Total Metered Loads (MW)</td><td></td></tr>
<tr><td>4. TDSP Design Contact</td><td colspan="2"></td><td colspan="2">8. Power Generation Co.</td><td></td></tr>
<tr><td>5. Design Contact Phone #</td><td colspan="2"></td><td colspan="2">9. TDSP Project #</td><td></td></tr>
<tr><td>6. Design Contact E-Mail</td><td colspan="2"></td><td colspan="2">10. Facility Gross Capacity (MW)</td><td></td></tr>
<tr><td>11. TDSP Substation Name</td><td colspan="5"></td></tr>
<tr><td>12. Total # Gen. Meters</td><td></td><td>Total # Gen. Primary Meters</td><td></td><td>Total # Gen. Back-up Meters</td><td></td></tr>
<tr><td>13. Total # Load Meters</td><td></td><td>Total # Load Primary Meters</td><td></td><td>Total # Load Back-up Meters</td><td></td></tr>
<tr><td>14. Metering Purpose</td><td colspan="5"></td></tr>
<tr><td colspan="2">15. Netting Information</td><td colspan="4">Describe any netting requirements for this installation. (e.g., Auxiliary loads fed from a common switchyard, load netting behind the metering point, etc.) Specify under which section of Protocol Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, netting is being requested.</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td colspan="3">16. Facility Comments</td><td colspan="3">Please include any clarifying information.</td></tr>
<tr><td colspan="6"></td></tr>
<tr><td colspan="6">17. Resource Owner Agreement with the EPS Metering Design Proposal</td></tr>
<tr><td>18. Resource contact</td><td colspan="2"></td><td colspan="2">19. Resource contact E-mail</td><td></td></tr>
<tr><td>20. Resource contact phone #</td><td colspan="2"></td><td colspan="2">21. Resource owner agreement with design proposal</td><td></td></tr>
</table>

B. METERING FACILITY DETAILS

22. Unit or Load Name		24. TDSP Project #	
23. Unit Capacity		25. Meter ID as shown on one-line	
26. Meter Form Designation			
27. Load description and size			
28. Metering Purpose			

29. Loss Compensation Information	Please describe any loss compensation that will be required at the installation. Include whether the compensation will be calculated in the meter (preferred) or if ERCOT will need to perform this calculation in the data aggregation system. State if loss compensation will not be programmed per paragraph (3) of the Section 8.4, Calculating Line Loss Constants, and provide a clarifying statement and/or supporting calculation.

30. Voltage Transformer Information				**31. Current Transformer Information**			
Name Plate	**A ∅**	**B ∅**	**C ∅**	**Name Plate**	**A ∅**	**B ∅**	**C ∅**
Manufacturer				Manufacturer			
Type				Type			
Ratio				Ratio/Rating factor			
Burden Rating				Burden Rating			
Acc. Class				Acc. Class			

32. Meter Point Comments

B. METERING FACILITY DETAILS

22. Unit or Load Name		24. TDSP Project #	
23. Unit Capacity		25. Meter ID as shown on one-line	
26. Meter Form Designation			
27. Load description and size			
28. Metering Purpose			

29. Loss Compensation Information	Please describe any loss compensation that will be required at the installation. Include whether the compensation will be calculated in the meter (preferred) or if ERCOT will need to perform this calculation in the data aggregation system. State if loss compensation will not be programmed per paragraph (3) of Section 8.4 and provide a clarifying statement and/or supporting calculation.

30(A). Voltage Transformer Information				31(A). Current Transformer Information			
Name Plate	**A ∅**	**B ∅**	**C ∅**	**Name Plate**	**A ∅**	**B ∅**	**C ∅**
Manufacturer				Manufacturer			
Type				Type			
Ratio				Ratio/Rating factor			
Burden Rating				Burden Rating			
Acc. Class				Acc. Class			

30(B). Voltage Transformer Information				31(B). Current Transformer Information			
Name Plate	**A ∅**	**B ∅**	**C ∅**	**Name Plate**	**A ∅**	**B ∅**	**C ∅**
Manufacturer				Manufacturer			
Type				Type			
Ratio				Ratio/Rating factor			
Burden Rating				Burden Rating			
Acc. Class				Acc. Class			

32. Meter Point Comments

C. TDSP ONE LINE DRAWING			
33. Drawing Number(s)			
34. TDSP Project #		35. TDSP	
TDSP		ERCOT	
Approved By	**Date Approved**	**Approved By**	**Date Approved**

<table>
<tr><td colspan="4">D. AUXILIARY LOAD TELEMETRY DETAILS</td></tr>
<tr><td>36. Unit or Load Name</td><td colspan="3"></td></tr>
<tr><td>37. TDSP Project #</td><td colspan="3"></td></tr>
<tr><td>38. Meter ID as shown on TDSP one-line</td><td colspan="3"></td></tr>
<tr><td>39. ESR Auxiliary Load Max Expected Value</td><td colspan="3"></td></tr>
<tr><td>40. WSL Calculation Location: Meter or Data Aggregation</td><td></td><td colspan="2">If WSL Calculation will be performed in the meter, supporting documents must be provided. List any supporting documents under Additional Comments\Documents in D48.</td></tr>
<tr><td>Resource Entity Provided Supporting Documents</td><td colspan="3">Please provide the name of the documents/drawings provided by the Resource Entity and submitted to support the auxiliary load calculation.</td></tr>
<tr><td>41. Confirmation that ESR Auxiliary Load Cannot be Separately Metered</td><td colspan="3"></td></tr>
<tr><td>42. Load calculation equipment and methodology</td><td colspan="3"></td></tr>
<tr><td>43. Description of performed or planned testing to support accuracy</td><td colspan="3"></td></tr>
<tr><td colspan="2">Resource Entity Contact</td><td colspan="2">Name(s) of Resource Entity contact(s) providing the supporting documents.</td></tr>
<tr><td>44. Provided By</td><td></td><td>45. Date Provided</td><td></td></tr>
<tr><td>46. Contact E-mail Address(es)</td><td></td><td>47. Contact Phone Number(s)</td><td></td></tr>
<tr><td colspan="4">48. Additional Comments\Documents</td></tr>
<tr><td colspan="4"></td></tr>
</table>

A. FACILITY INFORMATION AND CONTACT INFORMATION

Facility Information and Contact Information

Specific information for the entire facility covered by the EPS Metering Design Proposal. Only one Facility Information and Contact Information section should be completed for each design proposal.

1. Facility name:

The name the Resource Entity lists in the Resource Registration information used to register the Resource with ERCOT. When Resource Registration information is not available, it should be the name the TDSP uses to describe the Non-Opt-In Entity (NOIE) meter point or Direct Current Tie (DC Tie) facility.

2. Facility address (physical):

This should be the physical address or location by description of the EPS metering facility. PO Box # or other type of address that does not define the geographical or physical location is unacceptable.

3. TDSP:

The **T**ransmission and/or **D**istribution **S**ervice **P**rovider that is responsible for the installation and maintenance of this EPS Metering Facility.

4. TDSP Design contact:

The individual that will be assigned to this project and can answer questions about the proposed design and installation.

5. TDSP design contact phone number:

The phone number at which the TDSP design contact can be reached during business hours.

6. TDSP design contact e-mail address:

TDSP design contact e-mail address

7. Total metered Loads (MW)**:**

The total MW of Loads served by EPS Meters for the EPS Metering Design Proposal.

Note: For Bi-directional metering points, the total metered Loads is the sum of the estimated peak loads that will flow for this site as recorded be channel 1 of the EPS meters.

8. Power Generation Company:

The company name registered with ERCOT of the Market Participant (Resource owner) that owns/operates the generation facility.

9. TDSP project number:

A unique tracking number created by the TDSP for each EPS Metering Design Proposal package submitted to ERCOT.

*Note: a dash 1, 2, 3, or a dash A, B, C etc.… after the “base” project number is allowable for the metering facility details and one line drawings.

10. Facility gross capacity (MW)**:**

The total rated **M**ega **W**att capacity of the facility. In the case of generation facilities with multiple generating units, this would be the sum of all the units included in the EPS Metering Design Proposal and should match the total generation capacity listed in the Resource Registration information.
*Note: For Bi-directional metering points, the gross capacity is the sum of the estimated peak generation that will flow into the ERCOT System for this site as recorded by channel 4 of the EPS meters.

11. TDSP substation name:
The name the TDSP will use to identify the substation in which the EPS Meter is physically located.

12. Total number of generation meters:
Count of EPS Meters metering the generation output at the facility. This shall be the total count of all primary and back-up generation meters.
*Note: Bi-directional metering points shall be listed as generation meters.

13. Total number of Load meters:
Count of EPS Meters metering only Loads at the facility. This shall be the total count of all primary and back-up load meters.

14. Metering purpose:
Why is this facility being metered? (i.e. Market Participant generation, radial load point, Bi-directional NOIE metering Point, DC Tie between ERCOT and Non-ERCOT transmission system, Elected optional NOIE lateral feed meter point, etc.)

15. Netting Information:
Netting information that ERCOT will use to determine the “Net Generation” or “Load” of the facilities, represented by the EPS Metering Design Proposal, for settlement purposes. TDSP to provide a statement specifying the section of Protocol Section 10.3.2.3 netting is being requested under. The statement shall confirm that the resource site meets the requirements in the specified section of Protocol Section 10.3.2.3.

16. Facility Comments:
Any information that further describes a unique EPS metering arrangement that the TDSP needs to convey to help clarify the installation for settlement purposes as it applies to the whole facility.

17. Resource owner agreement with the EPS Metering Design Proposal:
For a design proposal connecting a generation unit, the Resource owner needs to review and be in agreement with the EPS Metering Design Proposal. The TDSP is responsible to communicate the EPS Metering Facility design to the Resource owner and that the Resource owner is in agreement with all aspects of the design proposal.

18. Resource Owner Contact:
For a design proposal connecting a generation unit, the representative for the Resource owner that is in agreement with the EPS Metering Design Proposal.

19. Resource contact e-mail address:
For a design proposal connecting a generation unit, the Resource owner’s contact e-mail address.

20. Resource contact phone number:
For a design proposal connecting a generation unit, the telephone-number where the Resource owner's contact can be reached during business hours.

21. Resource owner agreement with design proposal:
For a design proposal connecting generation unit the Resource owner's agreement with the design proposal is indicated with a "yes" or "Y".

B. METERING FACILITY DETAILS

Metering Facility Details Form:

Specific information for each metering point included in the EPS Metering Design Proposal. A "Metering Facility Details" form will need to be completed for each EPS meter point. Please use the appropriate version of Part B throw-over voltage transformers and/or parallel current transformers are utilized. This section should be duplicated and additional copies of Section B should be used for each meter point of the facility.

22. Unit or Load Name:
This field refers to the individual Resource or Load being metered by the EPS metering installation. For Resources, this is the name the Generation Unit used to register the Resource. For Loads this is a name describing the metering point.

23. Unit Capacity:
This is the rated gross generation unit capacity in MW for the EPS Metering point as recorded in the meter by channel 4.
*Note: For Bi-directional metering points, the unit capacity is the estimated peak generation that will flow through this point.

24. TDSP Project #:
A number assigned by the TDSP to each EPS Metering Design Proposal. This number should be limited to ten (10) alphanumeric characters and should match the number assigned in box A10.

25. Meter ID as shown on one-line:
All one-line diagrams submitted to ERCOT showing EPS metering installation locations shall have an ID designated by the TDSP to label each meter point shown with a unique identifier designated by the TDSP.

26. Meter Form Designation:
The form designation identifies a meter for a particular application.

27. Load:
Describe the type and size (in Megawatts) of the Load served by the EPS Meter for the EPS Metering point as recorded in the meter by channel 1.
*Note: For Bi-directional metering points, the Load is the estimated peak consumption that will flow through this point.

28. Metering purpose:
Why is this facility being metered? (i.e. Market participant generation, radial load point, Bi-directional NOIE metering Point, DC Tie between ERCOT and Non-ERCOT transmission system, Elected optional NOIE lateral feed meter point, etc.…)

29. Loss Compensation:
Describe any loss compensation that will be required at the installation. Include whether the compensation will be calculated in the meter or if ERCOT is being requested to perform this calculation. If ERCOT is being request to perform the calculation, please provide the fixed loss compensation value indicating the value for load and/or generation channels. If using a fixed value, please submit additional documentation along with the design proposal indicating how the values were derived.
If the meter is not located at the Point of Interconnection (POI) and line loss compensation will not be programmed per paragraph (3) of Section 8.4, a statement regarding connections per paragraph (3)(a) of Section 8.4 or the calculation required per paragraph (3)(b) of Section 8.4 must be provided.

30. Voltage Transformer Information:
This is industry standard nameplate information available on instrument transformers.

31. Current Transformer Information:
This is industry standard nameplate information available on instrument transformers.

32. Meter Point Comments:
Provide any clarifying comments specific to the meter point. Examples include manufacture statements regarding CT accuracy, elaborations on instrument transformer selection or any other supporting information for the meter point.

C. TDSP ONE LINE DRAWING

A one line drawing should be of sufficient detail to allow verification of the accurate settlement metering of Resources and Loads at EPS Metering Facilities. The drawing should allow the design philosophy, instrument transformer locations, netting scheme, compensation scheme and any breakers isolating loads from generation to be understood.

For current transformer (CT), indicate CT ratio, accuracy, and rating factor on the one-line drawing. The CT polarity should also be shown along with the meter connections to the CT to allow for verification that energy will be recorded in the correct channels. For voltage transformer (VT), indicate VT ratio and accuracy. Meter ID(s) must also be on the one-line drawing.

D. AUXILIARY LOAD TELEMETRY DETAILS

Telemetry Details Form:

Specific information for each ESR Auxiliary Load Telemetry being supplied to an EPS meter included in the EPS Metering Design Proposal. A “Auxiliary Load Telemetry Details” form will need to be completed for each EPS meter point that has ESR Auxiliary Load Telemetry supplied. This section should be duplicated and additional copies of this Section D should be used for each ESR Auxiliary Load Telemetry provided to an EPS meter. The information in this Section should be provided by the resource owner to the TDSP.

36. Unit or Load Name:
This field refers to the individual meter point that the ESR Auxiliary Load Telemetry is being supplied to. This name should match the TDSP supplied name from B22.

37. TDSP Project #:
A number assigned by the TDSP to each EPS Metering Design Proposal. This number should be limited to ten (10) alphanumeric characters and should match the number assigned in box A10.

38. Meter ID as shown on TDSP one-line:
This should be the name of the meter that will be supplied ESR Auxiliary Load Telemetry as listed on the TDSP one-line diagrams supplied with the Design Proposal. This name should match the TDSP supplied name from B25.

39. ESR Auxiliary Load Max Expected Value:
The maximum of load value that the resource entity expects the ESR auxiliary load to draw while the ESR is charging**.**

40. WSL Calculation Location: Meter or Data Aggregation:
Indicate if the wholesale storage load value will be calculated in the EPS meter or if it will be performed in the ERCOT Data Aggregation system. If the WSL will be calculated in the meter, include supporting documents showing how the calculations will be performed in compliance with paragraph (3)(a) of Protocol Section 11.1.6, ERCOT-Polled Settlement Meter Netting, and paragraph (1)(c) of Section 4.1, Standard IDR Channel Assignments. Supporting documents should be listed in box D49 “Additional Comments\Documents”.

41. Confirmation that ESR Auxiliary Load Cannot be Separately Metered:
Documentation describing the reason that the auxiliary load meets the requirement of paragraph (1) of Protocol Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values, and cannot be separately metered and must be calculated. This shall include a one-line drawing that includes facility details necessary to understand the calculation and data flow.

42. Load calculation Equipment and Methodology:
A description of the equipment and method used to determine the auxiliary load value and telemeter the auxiliary load value to the appropriate EPS meter shall be provided. This description shall include how the calculated auxiliary load will always be equal to or greater than the true auxiliary load, the equipment used in determining the auxiliary load calculation, and the accuracy of equipment used. If a zero load value will be telemetered while the ESR is discharging, the methodology for determining when zero will be telemetered must be included in the description.

43. Description of performed or planned testing to support accuracy:

A description of the anticipated annual certification process, and any laboratory or field testing that has already been performed. Documentation will describe what actions have been taken and will be taken on an ongoing basis, to ensure that the overall initial correction factor applied to the calculated auxiliary AC load of each battery system component will not understate the load value reported via site telemetry. This includes confirmation by the Texas Professional Engineer that laboratory testing and/or field testing has been or will be conducted on the specified sensor models used at the site, to establish the long-term accuracy of the sensor as a result of long-term degradation which may occur naturally in the field. Such documentation may reference utilization of sensor OEM test data, sensor OEM specifications, and/or analysis of the materials and design of the sensor. It may also include the results of accelerated life cycling conducted to represent the intended life of the deployed system on the sensor suite, a proposal to remove a sample of sensors to test their accuracy using NIST-traceable test equipment under anticipated field conditions, or, other actions required by a Texas Professional Engineer.

44. Provided By:
Name of the Resource Entity representative that is providing the supporting documents. This may be multiple contacts.

45. Date Provided:
Date the Resource Entity contact in D45 provided the supporting documents.

46. Contact E-mail Address(es):
Contact e-mail address for the Resource Entity representative(s) listed in D44.

47. Contact Phone Number(s):
Contact phone number(s) for the Resource Entity representative(s) listed in D44.

48. Additional Comments\Documents:
Provide any clarifying comments or names of additional supporting documents.

Settlement Metering Operating Guide
Section 12
Attachment B

EPS Metering Facility Temporary Exemption Request Application Form

May 1, 2024

Application Form for an EPS Metering Facility Temporary Exemption Request ***Submit completed form to epsmetering@ercot.com***		Application Date	
Applicant's Name		Applicant's Phone #	
TDSP Project #		TDSP Name	
Design Proposal Approval Date			
Design Proposal Facility Name			
Design Proposal Unit or Load Name			
Design Proposal Meter ID			
Resource owner contact that has agreed to this exemption request.	Name	E-mail	
Provide a detailed description of the exemption request below			
Provide the relevant section of Protocols or SMOG the exemption will apply to			
Provide a detailed statement on the reason for seeking the exemption			
Proposed Start Date of exemption			
Proposed Stop Date of exemption			
Note: If the proposed start or stop dates change, notify epsmetering@ercot.com with the changes			
Will ERCOT be able to poll the meter during the exemption period? ***(Yes/No)***			
If no, explain how meter data will be provided / estimated for Settlement			
Does the exemption request affect the accuracy of the registered energy flow? ***(Yes/No)***			
If yes, provide a detailed explanation			
Approved by ERCOT			
Date		Person	