ERCOT Nodal Operating Guides

February 1, 2026

ERCOT Nodal Operating Guide
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ERCOT Nodal Operating Guides

Section 1: Overview

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1 OVERVIEW

1.1 Document Purpose

(1) These ERCOT Operating Guides supplement the Protocols. The Operating Guides provide more detail and establish additional operating requirements for those organizations and Entities operating in, or potentially impacting the reliability of the ERCOT Transmission Grid in the ERCOT Region.

(2) The title "Operating Guide" is not to be construed as presenting merely a recommendation. Organizations and Entities are obligated to comply with the Operating Guides. Specific practices described in the Operating Guides for the ERCOT Region are consistent with North American Electric Reliability Corporation (NERC) Reliability Standards and the Protocols.

1.2 Document Relationship

(1) These Operating Guides are written to be consistent with the Protocols and to implement the North American Electric Reliability Corporation (NERC) Reliability Standards. The Protocols supersede these Operating Guides. The Public Utility Commission of Texas (PUCT) rules contain additional requirements for ERCOT and connected Entities.

(2) For application in the ERCOT Region, some NERC Reliability Standards must be adapted to fit the unique characteristics of ERCOT. Defined terminology for NERC Regional Variances, if any, is detailed in the NERC Reliability Standards.

1.3 Process for Nodal Operating Guide Revision

1.3.1 Introduction

(1) A request to make additions, edits, deletions, revisions, or clarifications to these Operating Guides, including any attachments and exhibits to these Operating Guides, is called a Nodal Operating Guide Revision Request (NOGRR). Except as specifically provided in other sections of these Operating Guides, Section 1.3, Process for Nodal Operating Guide Revision, shall be followed for all NOGRRs. ERCOT Members, Market Participants, Public Utility Commission of Texas (PUCT) Staff, the Reliability Monitor, the North American Electric Reliability Corporation (NERC) Regional Entity, the Independent Market Monitor (IMM), 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 these Operating Guides, except for good cause shown to the PUCT or other Governmental Authority.

(2) The "next regularly scheduled meeting" of the Reliability and Operations Subcommittee (ROS), 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) The ROS shall ensure that the Operating Guides are compliant with the ERCOT Protocols. As such, the ROS will monitor all changes to the ERCOT Protocols and initiate any NOGRRs necessary to bring the Operating Guides in conformance with the ERCOT Protocols. The ROS will also initiate a Nodal Protocol Revision Request (NPRR) if such a change is necessary to accommodate a proposed NOGRR prior to proceeding with that NOGRR.

(4) Throughout the Operating Guides, references are made to the ERCOT Protocols. ERCOT Protocols supersede the Operating Guides and any NOGRR must be compliant with the 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 NOGRR. Under certain circumstances, however, the Operating Guides can also be revised by ERCOT rather than using the NOGRR process outlined in Section 1.3.

(a) This type of revision is referred to as an "Administrative NOGRR" 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 1.3 and Protocol Section 21.

(b) ERCOT shall post such Administrative NOGRRs to the ERCOT website and distribute the NOGRR to ROS. If no Entity submits comments to the Administrative NOGRR within ten Business Days in accordance with paragraph (1) of Section 1.3.3.3, ROS Review and Action, the Administrative NOGRR shall be subject to PUCT approval. Following PUCT approval, ERCOT shall implement the Administrative NOGRR according to paragraph (3) of Section 1.3.5, Nodal Operating Guide Revision Implementation. If any Entity submits comments to the Administrative NOGRR, then it shall be processed in accordance with the NOGRR process outlined in Section 1.3.

(6) ERCOT may make modifications to the Operating Guides for the purpose of maintaining duplicate language between the Protocols and the related sections of the Operating Guides.

(a) This type of revision is referred to as an "Alignment NOGRR" and shall consist of changes to align language in the Protocols with related language in the Operating Guides. The following Operating Guide sections may only be modified by an Alignment NOGRR:

(i) Section 4.5.3.3, EEA Levels.

(b) ERCOT shall post an Alignment NOGRR to the ERCOT website and distribute the Alignment NOGRR to ROS within five Business Days of the ERCOT Board recommending approval of the related NPRR. The Alignment NOGRR shall be subject to PUCT approval. Alignment NOGRRs shall be implemented according to paragraph (5) of Section 1.3.5, rather than using the NOGRR process outlined in Section 1.3, and are exempt from the NOGRR comment process described in paragraph (2) of Section 1.3.3.3.

1.3.2 Submission of a Nodal Operating Guide Revision Request

(1) The following Entities may submit a NOGRR:

(a) Any Market Participant;

(b) Any ERCOT Member;

(c) PUCT Staff;

(d) The Reliability Monitor;

(e) The NERC Regional Entity;

(f) The IMM;

(g) ERCOT; and

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

(i) Resides (or represent 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.

1.3.3 Nodal Operating Guide Revision Procedure

1.3.3.1 Review and Posting of Nodal Operating Guide Revision Requests

(1) NOGRRs shall be submitted electronically to ERCOT by completing the designated form provided on the ERCOT website. Excluding ERCOT-sponsored NOGRRs, ERCOT shall provide an electronic return receipt response to the submitter upon receipt of the NOGRR.

(2) The NOGRR 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 Operating Guide sections and subsections;

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

(e) Suggested language for requested revision.

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

(4) If a submitted NOGRR is complete or upon completion of a NOGRR, ERCOT shall post the NOGRR on the ERCOT website and distribute to the ROS within three Business Days.

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

1.3.3.2 Withdrawal of a Nodal Operating Guide Revision Request

(1) A submitter may withdraw or request to withdraw a NOGRR 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 NOGRR may withdraw the NOGRR at any time before ROS recommends approval of the NOGRR.

(3) If ROS has recommended approval of the NOGRR, the Request for Withdrawal must be approved by TAC if the NOGRR has not yet been recommended for approval by TAC.

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

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

1.3.3.3 ROS Review and Action

(1) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the NERC Regional Entity, the IMM, or ERCOT may comment on the NOGRR.

(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 NOGRR. Comments posted after the 14-day comment period may be considered at the discretion of ROS. 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 ROS within three Business Days of submittal.

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

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

(b) Reject the NOGRR;

(c) Table the NOGRR; or

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

(4) If a motion is made to recommend approval of a NOGRR and that motion fails, the NOGRR shall be deemed rejected by ROS unless at the same meeting ROS later votes to recommend approval of, table, or refer the NOGRR. If a motion to recommend approval of an NOGRR fails via e-mail vote according to the Technical Advisory Committee Procedures, the NOGRR shall be deemed rejected by the ROS unless at the next regularly scheduled ROS meeting or in a subsequent e-mail vote prior to such meeting, ROS votes to recommend approval of, table, or refer the NOGRR. The rejected NOGRR shall be subject to appeal pursuant to Section 1.3.3.12, Appeal of Action.

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

(a) Identification of submitter of the NOGRR;

(b) Operating Guide language recommended by ROS, if applicable;

(c) Identification of authorship of comments;

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

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

(f) ROS action.

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

1.3.3.4 Comments to the ROS Report

(1) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the NERC Regional Entity, the IMM, or ERCOT may comment on the ROS 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., ROS and/or TAC) considering the NOGRR within three Business Days of submittal.

(2) The comments to the ROS Report will be considered at the next regularly scheduled ROS meeting that is at least six days from the posting date. Comments posted less than six days prior to the next regularly scheduled ROS meeting may be considered at the discretion of the ROS.

(3) For TAC, the comments to the ROS Report will be considered at the next regularly scheduled TAC meeting where the Revision Request is being considered.

1.3.3.5 Nodal Operating Guide Revision Request Impact Analysis

(1) If ROS recommends approval of a NOGRR, ERCOT shall prepare an Impact Analysis based on the proposed language in the ROS 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 ROS Report.

(2) The Impact Analysis shall assess the impact of the proposed NOGRR 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 NOGRR;

(c) The identification of alternatives to the NOGRR 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 ROS Report, ERCOT shall post an Impact Analysis on the ERCOT website for a NOGRR for which ROS has recommended approval of, prior to the next regularly scheduled ROS meeting, and distribute to ROS. 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.

1.3.3.6 ROS Review of Impact Analysis

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

(2) Within three Business Days of ROS consideration of the Impact Analysis and ROS Report, ERCOT shall post the ROS Report on the ERCOT website. If ROS revises the ROS 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. ROS 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 NOGRR requires an ERCOT project for implementation, at the same meeting, ROS shall assign a recommended priority and rank for the associated project.

1.3.3.7 ERCOT Impact Analysis Based on ROS Report

(1) ERCOT shall review the ROS 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.

1.3.3.8 PRS Review of Project Prioritization

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

1.3.3.9 Technical Advisory Committee Vote

(1) TAC shall consider any NOGRR that ROS has submitted to TAC for consideration for which both a ROS Report and an Impact Analysis (as updated if modified by ROS under

Section 1.3.3.7, ERCOT Impact Analysis Based on ROS Report) have been posted on the ERCOT website. The following information must be included for each NOGRR considered by TAC:

(a) The ROS Report and Impact Analysis;

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

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

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

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

(b) Reject the NOGRR;

(c) Table the NOGRR;

(d) Remand the NOGRR to ROS with instructions; or

(e) Refer the NOGRR 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 NOGRR and that motion fails, the NOGRR shall be deemed rejected by TAC unless at the same meeting TAC later votes to recommend approval of, table, remand, or refer the NOGRR. If a motion to recommend approval of an NOGRR fails via email vote according to the Technical Advisory Committee Procedures, the NOGRR shall be deemed rejected by TAC unless at the next regularly scheduled TAC meeting or in a subsequent email vote prior to such meeting, TAC votes to recommend approval of, table, remand, or refer the NOGRR. The rejected NOGRR shall be subject to appeal pursuant to Section 1.3.3.12, Appeal of Action

(4) Within three Business Days after TAC takes action on a NOGRR, 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 NOGRR;

(b) Modified Nodal Operating Guide language proposed by TAC, if applicable;

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

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

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

(f) ROS action;

(g) TAC action;

(h) IMM Opinion;

(i) ERCOT Opinion; and

(j) ERCOT Market Impact Statement.

(5) If TAC recommends approval of a NOGRR, ERCOT shall forward the TAC Report to the ERCOT Board for consideration pursuant to Section 1.3.3.10, ERCOT Board Vote.

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

1.3.3.10 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 NOGRRs, 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 NOGRR.

(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 NOGRR as recommended in the TAC Report or as modified by the ERCOT Board;

(b) Reject the NOGRR;

(c) Table the NOGRR; or

(d) Remand the NOGRR to TAC with instructions.

(3) If a motion is made to recommend approval of a NOGRR and that motion fails, the NOGRR 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 NOGRR. The rejected NOGRR shall be subject to appeal pursuant to Section 1.3.3.12, Appeal of Action.

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

1.3.3.11 PUCT Approval of Revision Requests

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

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

1.3.3.12 Appeal of Action

(1) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the IMM, the NERC Regional Entity or ERCOT may appeal a ROS action to reject, table, or refer a NOGRR directly to 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 ROS 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 NOGRR to TAC suspends consideration of the NOGRR 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 NOGRR 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 NOGRR to the ERCOT Board suspends consideration of the NOGRR until the appeal has been decided by the ERCOT Board.

(3) Any ERCOT Member, Market Participant, PUCT Staff, the Reliability Monitor, the IMM, or the NERC Regional Entity may appeal any decision of the ERCOT Board regarding a NOGRR 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 NOGRR, ERCOT shall post the ruling on the ERCOT website.

1.3.4 Urgent Requests

(1) The party submitting a NOGRR may request that the NOGRR be considered on an urgent timeline ("Urgent") only when the submitter can reasonably show that an existing Nodal Operating Guide 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) ROS may designate the NOGRR for Urgent consideration if a submitter requests Urgent status or upon valid motion in a regularly scheduled meeting of the ROS. Criteria for designating a NOGRR as Urgent are that the NOGRR 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 a Settlement activity conducted pursuant to any Settlement formula.

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

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

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

(6) If recommended for approval by ROS, ERCOT shall post a ROS Report on the ERCOT website within three Business Days after ROS takes action. The 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 NOGRRs shall be subject to an Impact Analysis pursuant to Section 1.3.3.7, ERCOT Impact Analysis Based on ROS Report, and TAC consideration pursuant to Section 1.3.3.9, Technical Advisory Committee Vote.

1.3.5 Nodal Operating Guide Revision Implementation

(1) Following PUCT approval, ERCOT shall implement NOGRRs on the first day of the month following PUCT approval, unless otherwise provided in the PUCT Report for the approved NOGRR.

(2) For such other NOGRRs, the Impact Analysis shall provide an estimated amount of time required to implement the NOGRR 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 NOGRR.

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

(4) ERCOT shall implement an Alignment NOGRR as provided in the PUCT Report for the related NPRR.

1.4 Definitions

A primary list of definitions is contained within Protocol Section 2, Definitions and Acronyms. Additional definitions that apply specifically to these Operating Guides are listed below. It is essential to the reliability of the ERCOT Transmission Grid that all appropriate personnel use and understand the same terms in their daily operations. The definitions in this Section are intended to enable ERCOT, Qualified Scheduling Entities (QSEs), and Transmission Operators (TOs) to effectively communicate on an ongoing basis.

LINKS TO DEFINITIONS:

A, B, C, D, E, F, G, H, I, J, K, L, M, N, O, P, Q, R, S, T, U, V, W, X, Y, Z;

A

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Automatic Generation Control (AGC)

Application that receives signals from ERCOT for Regulation deployment and causes Resources providing these Ancillary Services to respond in accordance with their ramp rate to meet the received deployments.

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Capacitor

Static device which produces reactive power (VAr source) for voltage control when energized (tends to raise voltage).

Cranking Path

A set of elements in the ERCOT System that establishes an electrical path from a contracted Black Start Resource to a designated next start Resource.

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Designated Agent

Any Entity that is authorized to perform actions or functions on behalf of another Entity.

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Generator Reactive Power Sign/Direction Terminology

(1) Lagging power factor operating condition is when MVAr flow is out of the Generation Resource (overexcited generator) or Energy Storage Resource (ESR). The generator is producing MVArs.

(2) Leading power factor operating condition is when MVAr flow is into the Generation Resource (underexcited generator) or ESR. The generator is absorbing MVArs.

Geomagnetic Disturbance (GMD)

A disturbance of the earth's magnetic field caused by the interaction of that field with the effects of solar storms. These GMDs may result in induced currents that may negatively affect power system equipment.

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Inadvertent Energy

The difference between the ERCOT System actual metered value and the ERCOT System scheduled energy.

Intercompany Connections

The connection between two or more independent transmission companies.

Inter-Control Center Communication Protocol (ICCP) Data

Data that is transmitted or exchanged over the ICCP link and the subject of any provisions of the Nodal ICCP Communication Handbook.

Intra-Company

Occurring within or between the branches of a single company.

Island

An electrically separated portion of the ERCOT System with independent frequency, generation and Load.

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Resource-Specific Extensible Markup Language (XML) Data

XML Data gathered, transmitted, or exchanged pursuant to the ERCOT Protocols that identifies a specific Resource and/or relates to the deployment or recall of an Emergency Response Service (ERS) Resource. This definition does not include reports and extracts retrieved via the Market Information System (MIS).

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Synchronization Corridors

A predetermined section of the ERCOT Transmission Grid that may be utilized to synchronize Islands after a Partial Blackout or Blackout.

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Telemetry

The measured quantity or quality (e.g., open/closed, amps, volts, MW, MVAr, MVA) and transmitting the result to a remote location for indication or recording.

Time Error

An accumulated time difference between ERCOT System time and the time standard. Time error is caused by a deviation in ERCOT average frequency from 60.0 Hz.

Transmission Line Terminal Sign/Direction Terminology

(1) MW or MVAr flow out of the bus is considered to be positive (+) flow.

(2) MW or MVAr flow into the bus is considered to be negative (-) flow.

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1.5 Operational Training

1.5.1 System Operator Training Objectives

(1) Each operating Entity within the ERCOT System shall train its operators such that they will possess the necessary knowledge, skills and abilities to perform their assigned tasks in directing the operation of the bulk power system. Instruction provided shall be in accordance with North American Electric Reliability Corporation (NERC) Reliability Standards, the Protocols, these Operating Guides, and ERCOT Procedures, as well as individual Entity operating goals, plans and procedures.

(2) Training will prepare operators to:

(a) Maintain the safety of personnel, even during emergency situations involving complex switching and manipulation of control elements;

(b) Protect system components, particularly major power system elements from serious life degradation or harm;

(c) Operate the system in a secure manner to minimize violations of operating limits, avoiding customer Outages where reasonably possible, and avoiding unstable situations that might result in widespread Outages, Partial Blackouts or Blackouts;

(d) Operate the system using Good Utility Practices whenever possible within continually changing operating environment; and

(e) Restore the system to its normal operating state as rapidly as practical after a disturbance.

1.5.2 System Operator Training Requirements

(1) The System Operator Training Program applies to all operators who are responsible for the Day-Ahead and Real-Time operation of the ERCOT Transmission Grid. Transmission Operators (TOs) and Qualified Scheduling Entity (QSE) operators who represent Generation Resources, Energy Storage Resources (ESRs), and Load Resources shall participate in 32 hours per year of training and drills on system emergencies. QSE operators who do not represent Generation Resources, ESRs, or Load Resources must participate in at least eight hours per year of training and drills in system emergencies.

(2) For those operators required to obtain 32 hours annually at least eight hours must be from simulations or realistic drills.

(3) Training should use simulations appropriate to each class of operator and all such training shall meet or exceed established NERC Reliability Standards.

(4) Participation in emergency simulations, severe weather drills, ERCOT Black Start training, and portions of the ERCOT Operations Training Seminar that relate to NERC recommended topics may be used to satisfy this requirement.

(5) ERCOT Black Start training attendance is mandatory for all TOs, QSEs identified in a Black Start restoration plan, Resource Entities that represent Black Start Resources, and other Entities who are notified by ERCOT that their participation is required.

[NOGRR194: Replace paragraph (5) above with the following upon system implementation of NPRR857:]

(5) ERCOT Black Start training attendance is required for all TOs, Direct Current Tie Operators (DCTOs), QSEs identified in a Black Start restoration plan, Resource Entities that represent Black Start Resources, and other Entities who are notified by ERCOT that their participation is required.

(6) Attendance at Black Start training is limited to those Entities identified in paragraph (5) above, ERCOT staff, Public Utility Commission of Texas (PUCT), Reliability Monitor, or other Entities deemed by ERCOT to have a legitimate reliability reason to attend.

(7) Task specific training carried out internally within an Entity will be considered in full compliance with this requirement. Training documentation, including curriculum, training methods, and individual training records, shall be immediately available during any audit.

1.5.3 ERCOT Operations Training Seminar

(1) ERCOT will, at a minimum, annually host a training seminar. The purpose of the training seminar is to provide a forum for system wide problems to be effectively addressed, analyze common topics and issues, and participate in formal training sessions. The training seminar should present information to maintain the consistency of operators across all of the ERCOT Region.

(2) The seminar shall include a minimum of one topic on system restoration.

1.5.4 ERCOT Severe Weather Drill

(1) An annual severe weather drill will be held to test the scheduling and communication functions of the primary and/or backup control centers and to train operators in emergency procedures. On an annual basis, ERCOT shall:

(a) Develop and coordinate, with assistance from the Operations Working Group (OWG), the severe weather drill;

(b) Conduct a severe weather drill; and

(c) Verify and report Entity participation in the severe weather drill to the OWG, the Reliability Monitor, and the NERC Regional Entity.

(2) TOs and QSEs that represent Generation Resources and/or ESRs are required to participate in the severe weather drill.

(3) On an annual basis, OWG shall:

(a) Review and critique the results of completed severe weather drills to ensure effectiveness and recommend changes as necessary to ERCOT; and

(b) Report results of the severe weather drill to the Reliability and Operations Subcommittee (ROS).

1.5.5 Training Practices

(1) Each operating Entity should establish a clear requirement, define and develop a systematic approach in administering the training, and provide the necessary feedback as a measurement of curriculum suitability and trainee progress. Each operating Entity should recognize the importance of training and provide sufficient operator participation through adequate staffing and work-hour scheduling.

1.5.6 ERCOT Operator Certification Program

(1) ERCOT shall maintain and administer the ERCOT operator certification program, which includes the ERCOT Fundamentals Training Manual and certification exam. The purpose of the program is to prepare operators within the ERCOT Region to reliably operate the ERCOT System. ERCOT shall maintain the ERCOT Fundamentals Training Manual to serve as a reference for persons preparing for the ERCOT operator certification exam. ERCOT shall post the ERCOT Fundamentals Training Manual to the ERCOT website.

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2 SYSTEM OPERATIONS AND CONTROL REQUIREMENTS

2.1 Operational Duties

(1) The duties of ERCOT are described in relevant sections of the Protocols and North American Electric Reliability Corporation (NERC) Reliability Standards. These Operating Guides assume that all actions taken will be on components of, or related to, the ERCOT System unless otherwise specified. The primary operational duties of ERCOT are to ensure the reliability of the ERCOT System. In doing this ERCOT shall:

(2) Perform operational planning:

(a) Perform the Reliability Unit Commitment (RUC) processes in order to commit additional resources as needed to maintain reliability;

(b) Perform operational ERCOT Transmission Grid reliability studies, including those related to generation and load interconnection responsibilities;

(c) Review all Outages of Generation Resources, Energy Storage Resources (ESRs), and major transmission lines or components to identify and correct possible failure to meet credible N-1 criteria. This shall include possible failure to meet N-1 criteria not resolved through the Day-Ahead process;

(d) Perform load flows and security analyses of Outages submitted by Qualified Scheduling Entities (QSEs) or Transmission Service Providers (TSPs) as a basis for approval or rejection as described in Protocol Section 3.1, Outage Coordination;

[NOGRR177: Replace paragraph (d) above with the following upon system implementation of NPRR857:]

(d) Perform load flows and security analyses of Outages submitted by Qualified Scheduling Entities (QSEs), Transmission Service Providers (TSPs), or Direct Current Tie Operators (DCTOs) as a basis for approval or rejection as described in Protocol Section 3.1, Outage Coordination;

(e) Withdraw approval of a scheduled Outage if unable to meet credible N-1 criteria after all other reasonable options are exercised as described in Protocol Section 3.1;

(f) Serve as the point of contact for initiation of generation interconnection to the ERCOT Transmission Grid;

(g) Forecast Load and Resources for the next seven days for reliability planning; and

(h) Ensure that sufficient Resources in the proper location and required Ancillary Services have been committed for all expected Load on a Day-Ahead and Real-Time basis.

(3) Operate energy and Ancillary Service markets:

(a) Administer a Congestion Revenue Right (CRR) market;

(b) Administer a Day-Ahead Market (DAM) including both energy and Ancillary Service;

(c) Administer the RUC processes; and

(d) Administer a Real-Time Market (RTM) including energy and Ancillary Services using Security-Constrained Economic Dispatch (SCED).

(4) Supervise the ERCOT System to meet NERC Reliability Standards:

(a) Monitor and evaluate ERCOT System conditions on a continuous basis;

(b) Coordinate with Transmission Operators (TOs), ERCOT System events to maintain or restore reliability;

(c) Dispatch Generation Resources and ESRs via the SCED process and deployment of Ancillary Services to control frequency and congestion;

(d) Provide access to the ERCOT System on a nondiscriminatory basis;

(e) Approve schedules of interchange transactions across the Direct Current Ties (DC Ties); and

(f) Direct emergency operations.

(5) Collect and Disseminate Information:

(a) Collect, process, and disseminate market, operational and settlement information;

(b) Provide relevant operational information to Market Participants over the Market Information System (MIS);

(c) Collect and maintain operational data required by the Public Utility Commission of Texas (PUCT), NERC and Protocols;

(d) Receive reports from TOs and QSEs and forward them to the Department of Energy (DOE), NERC, and/or other Governmental Authority as required;

(e) Submit reports to DOE, NERC, and/or other Governmental Authority as required; and

(f) Record and report accumulated time error.

2.2 System Monitoring and Control

2.2.1 Overview

(1) ERCOT will maintain continuous surveillance of the status of operating conditions within ERCOT and act as a central information collection and dissemination point for Market Participants.

(2) ERCOT is designated to receive information required to continually monitor the operating conditions of the ERCOT System and to order individual Qualified Scheduling Entities (QSEs) and/or Transmission Operators (TOs) to make changes to ensure ongoing security and reliability of ERCOT.

(3) ERCOT shall maintain, monitor, and/or direct the following in accordance with the Protocols. This includes but is not limited to:

(a) Resources - Monitor, deploy, commit and gather data for settlement of Resources in order to maintain reliability and accurately settle energy capacity and Ancillary Service markets as described in the following Protocol Sections:

(i) Protocol Section 3, Management Activities for the ERCOT System;

(ii) Protocol Section 4, Day-Ahead Operations;

(iii) Protocol Section 5, Transmission Security Analysis and Reliability Unit Commitment; and

(iv) Protocol Section 6, Adjustment Period and Real-Time Operations.

(b) ERCOT Transmission Grid:

(i) Monitor line loading and power transfers;

(ii) Coordinate Planned Outages;

(iii) Monitor and detect Forced Outages;

(iv) Perform contingency analyses and direct re-dispatch to maintain reliable operations;

(v) Monitor and coordinate maintenance and construction schedules;

(vi) Monitor and control voltage levels; and

(vii) Monitor Reactive Power flows.

(c) System Operation:

(i) Monitor power flows with non-ERCOT systems;

(ii) Maintain and monitor Ancillary Services plans and delivery;

(iii) Maintain and document compliance with transmission security criteria;

(iv) Monitor performance of providers of Ancillary Services;

(v) Manage inadvertent energy account balances with non-ERCOT systems;

(vi) Direct Time Error correction;

(vii) Issue and direct Operating Condition Notices (OCNs), Advisories, Watches, and Emergency Notices; and

(viii) Direct emergency and short supply operations.

(d) Information Management:

(i) Monitor and coordinate information for daily planning, hourly reporting and minute-by-minute operation;

(ii) Validate the accuracy of the Real-Time data; and

(iii) Operate the Market Information System (MIS), Energy Management System (EMS) and Market Management System (MMS) to disseminate Real-Time, hourly accounting, and operations plan data between ERCOT and each QSE and TO.

2.2.2 Security Criteria

(1) Technical limits established for the operation of transmission equipment shall be applied consistently in planning and engineering studies, Congestion Revenue Rights (CRRs), Day-Ahead studies, Real-Time security analyses, and operator actions.

(2) ERCOT shall operate the system such that pre-contingency flows are within applicable Transmission Facility Ratings.

(3) ERCOT shall operate the system such that, unless an Emergency Condition has been declared by ERCOT, the occurrence of a Credible Single Contingency will not cause any of the following conditions:

(a) Uncontrolled breakup of the ERCOT Transmission Grid;

(b) Loading of Transmission Facilities above defined Emergency Ratings that cannot be eliminated in time to prevent damage or failure following the loss through execution of a Constraint Management Plan (CMP);

(c) Transmission voltage levels outside system design limits that cannot be corrected through execution of a CMP before voltage instability or collapse occurs; or

(d) Customer Outages, except for Load that is included in a CMP, high set interruptible and radially served Loads.

2.2.3 Response to Transient Voltage Disturbance

(1) Generation Resources and Energy Storage Resources (ESRs) should be designed in accordance with Section 6.2, System Protective Relaying, in order to properly respond to transient voltage disturbances.

2.2.4 Load Frequency Control

(1) ERCOT shall operate the Load Frequency Control (LFC) system to maintain the scheduled frequency at 60 Hz (correcting periodically for time error) and to minimize the use of energy from Resources providing Regulation Service.

(2) The ERCOT LFC system shall deploy Regulation Service, Responsive Reserve (RRS), and ERCOT Contingency Reserve Service (ECRS) as necessary in accordance with Protocol Section 6.5.7.6.2, LFC Deployment, to meet North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT shall purchase Regulation Service to provide satisfactory frequency control performance for the ERCOT Region. ERCOT shall determine the satisfactory amount of Regulation Service, required by statistical analysis of possible Resource Outages and Load forecast error, to expect operation of 95% of hours without deploying RRS.

(3) QSEs shall use Automatic Generation Control (AGC) to direct the output of Resources providing Regulation.

2.2.4.1 Maintenance and Verification

(1) Each provider of Regulation Services will properly maintain AGC equipment. Performance of AGC will be verified by the results of performance metrics for Ancillary Service providers described in the Protocols. ERCOT will initiate a regulation survey to evaluate the performance of all AGC equipment in the ERCOT Region.

2.2.4.2 Regulation Provider Loss of AGC

(1) If a QSE providing Regulation Services loses its AGC for any reason, it will notify ERCOT as soon as practicable of the reason for and estimated duration of the loss. ERCOT will assess whether additional action should be taken to maintain system frequency.

2.2.4.3 ERCOT Loss of AGC

(1) ERCOT has back-up facilities in place for loss of control systems. In the event that these backup facilities also fail to perform, ERCOT shall direct a QSE providing regulation to implement Constant Frequency Control (CFC) for the duration of the control loss. ERCOT will direct the QSE providing CFC to enter the appropriate bias into their control

system. If a QSE on CFC develops a problem with regulating room, ERCOT will order additional regulation energy from another QSE to create regulation room.

(2) ERCOT shall conduct unannounced testing to verify a QSE's capability to operate in CFC mode. Only QSEs with at least 350 MW of spinning reserve room will be tested. QSEs shall be tested at least once every three years. At a time determined solely by ERCOT, ERCOT will direct the QSE to operate under CFC mode. Once instructed by ERCOT, the QSE will have five minutes to switch to CFC mode. The duration of this test shall be no more than 15 minutes. ERCOT shall maintain the list of QSEs that have successfully demonstrated their capability to operate in CFC mode.

2.2.5 Automatic Voltage Regulators

(1) A Resource Entity shall immediately notify its QSE and its interconnecting TO of any change in Automatic Voltage Regulator (AVR) status (i.e., AVR unavailability due to maintenance or failure and when the AVR returns to normal operation). A QSE shall immediately notify ERCOT, via telemetry and verbal notification, of any change in AVR status and shall supply AVR status logs to ERCOT upon request per Protocol Section 6.5.5.1, Changes in Resource Status. For each Generation Resource that is On-Line but not producing real power and is not capable of providing Reactive Power, each QSE must still telemeter its AVR status to ERCOT, but is not required to provide verbal notifications of its AVR status changes to ERCOT during these operating conditions.

(2) Resource Entities shall conduct tests for the purpose of model verification on AVRs or verify AVR performance through comparison with operational data a minimum of every ten calendar years. All new Generation Resources shall conduct an AVR test as prescribed in paragraph (4) of Protocol Section 8.1.1.2.1.4, Voltage Support Service Qualification, within five years of the initial AVR test approved as part of the commissioning process. All subsequent tests shall be conducted on a ten year cycle. Additionally, if equipment characteristics are knowingly modified, an AVR test shall be conducted within 120 days of the modification. Industry accepted testing techniques shall be used for testing, measuring and calculating the modeling parameters. The test report must list the test(s) conducted or include the operational data used to verify the modeling parameters. Any models created from the test data must be a standard Power System Simulator for Engineering (PSS/E) dynamic model or ERCOT and Transmission Service Provider (TSP) approved user written model.

(a) Resource Entities will provide the test data or verified dynamic models to ERCOT by submittal to the Net Dependable Capability and Reactive Capability (NDCRC) application located on the MIS Secure Area or by updating its Resource Registration information respectively.

(b) All devices included in the AVR control system including but not limited to synchronous condensers, static Volt-Ampere reactive (VAr) compensators, static synchronous compensators (STATCOMs), and switchable shunt reactive devices required to meet Protocol Section 3.15, Voltage Support, shall be included in the

AVR test and set to regulate the transmission level voltage at the Point of Interconnection Bus (POIB).

[NOGRR204: Replace paragraph (2) above with the following upon system implementation of NPRR989:]

(2) Resource Entities shall conduct tests for the purpose of model verification on AVRs or verify AVR performance through comparison with operational data a minimum of every ten calendar years. All new Generation Resources and Energy Storage Resources (ESRs) shall conduct an AVR test as prescribed in paragraph (4) of Protocol Section 8.1.1.2.1.4, Voltage Support Service Qualification, within five years of the initial AVR test approved as part of the commissioning process. All subsequent tests shall be conducted on a ten year cycle. Additionally, if equipment characteristics are knowingly modified, an AVR test shall be conducted within 120 days of the modification. Industry accepted testing techniques shall be used for testing, measuring and calculating the modeling parameters. The test report must list the test(s) conducted or include the operational data used to verify the modeling parameters. Any models created from the test data must be a standard Power System Simulator for Engineering (PSS/E) dynamic model or ERCOT and Transmission Service Provider (TSP) approved user written model.

(a) Resource Entities will provide the test data or verified dynamic models to ERCOT by submittal to the Net Dependable Capability and Reactive Capability (NDCRC) application located on the MIS Secure Area or by updating its Resource Registration information respectively.

(b) All devices included in the AVR control system including but not limited to synchronous condensers, static Volt-Ampere reactive (VAr) compensators, static synchronous compensators (STATCOMs), and switchable shunt reactive devices required to meet Protocol Section 3.15, Voltage Support, shall be included in the AVR test and set to regulate the transmission level voltage at the Point of Interconnection Bus (POIB).

(3) Resource Entities shall verify excitation systems model data upon initial installation, within 120 days of performance modifications, and a minimum of ten calendar years thereafter.

(4) An exemption may be granted for the testing requirements listed in paragraphs (2) and (3) above if the Resource on which the AVR or excitation system is installed has an Annual Net Capacity Factor (ANCF) of 5% or less over the most recent three calendar years preceding the planned testing calendar year. ANCF is calculated as follows:

Annual Total Net Generation in MWHr/(Annual Hours * Average Seasonal Net Max Sustainable Rating) * 100%

Wherein:

Annual Hours = Number of hours in the calendar year being reported. Hours in mothball or retired status are not included in the hour total;

and

Average Seasonal Net Max Sustainable Rating = Average of the Seasonal Net Max Sustainable ratings submitted via the NDCRC application located on the MIS Secure Area.

(a) At the end of this ten year timeframe, the current average three year ANCF (for years eight, nine, and ten) will be examined by ERCOT to determine if the exemption can be declared for the next ten-year period. If no longer eligible for exemption based on the ANCF, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. Under certain operating conditions, ERCOT may require a ten year test even if the current average three year ANCF is below the 5% threshold.

(5) Black Start designated units are not eligible for the ANCF exemption detailed in paragraph (4) above. If a Resource that had been granted an exemption detailed in paragraph (4) above is accepted for Black Start Service (BSS), the Resource has 365 days from the start date of BSS to submit modeling information detailed in paragraph (2) above.

(6) Generation Resource AVR modeling information required in the ERCOT planning criteria shall be determined from actual Generation Resource testing described in these Operating Guides. Within 30 days of ERCOT's request, the results of the latest test performed shall be supplied to ERCOT and the TSP.

[NOGRR204: Replace paragraph (6) above with the following upon system implementation of NPRR989:]

(6) Generation Resource or ESR AVR modeling information required in the ERCOT planning criteria shall be determined from actual Generation Resource or ESR testing described in these Operating Guides. Within 30 days of ERCOT's request, the results of the latest test performed shall be supplied to ERCOT and the TSP.

2.2.6 Power System Stabilizers

(1) Synchronously interconnected Generation Resources and synchronously interconnected ESRs with Power System Stabilizers (PSSs) shall keep their PSSs in-service ("On" or energized and performing as designed by the manufacturer) unless the PSS is installed but not in service as described in paragraph (4)(a)(ii) below. When available, the PSS shall be active and responsive at all times the Resource is synchronized to the ERCOT Transmission Grid and operating at or above its Low Sustained Limit (LSL). However, if the PSS of a Resource is set to be active and responsive at a point above the LSL for technical reasons, the Resource may request ERCOT to allow an exception to the

requirement that the PSS be active anytime the Resource is at or above its LSL. In order to obtain the exception, the Resource shall notify ERCOT and provide the necessary technical information to ERCOT to justify a higher activation point for the PSS.

(2) Resource Entities shall notify their QSEs of any change in PSS status (e.g. PSS unavailability due to maintenance or failure and when the PSS returns to normal operation). QSEs shall notify ERCOT and the TO at the Point of Interconnection (POI) of any change in PSS status and shall supply PSS status logs to ERCOT upon request per Protocol Section 6.5.5.1, Changes in Resource Status.

(3) Synchronously interconnected Generation Resources and synchronously interconnected ESRs greater than 10 MW installed after January 1, 2008 and on or before December 1, 2010 shall install a PSS and place the PSS in service by June 1, 2011. Synchronously interconnected Generation Resources and synchronously interconnected ESRs greater than 10 MW installed after December 1, 2010 shall install a PSS and place the PSS in-service prior to the Resource Commissioning Date of the Generation Resource or ESR. The Generation Resource or ESR shall establish PSS settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz. The PSS settings shall be tested and tuned to ensure the PSS has appropriate damping characteristics. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(4) Synchronously interconnected Generation Resources and synchronously interconnected ESRs greater than 10 MW installed before January 1, 2008 are subject to the following requirements:

(a) All Generation Resources and ESRs that are in this category shall notify ERCOT and the TSP:

(i) Whether or not a PSS has been installed; and

(ii) Whether or not PSS settings have been determined and the PSS has been or will be placed in-service.

(b) If a PSS was in-service prior to January 1, 2008, the PSS shall remain in-service with the established PSS settings, provided that ERCOT may direct the Generation Resource or ESR to modify the settings. The PSS settings shall be tested and tuned to ensure the PSS has appropriate damping characteristics.

(c) If a PSS is newly installed and/or placed in-service the Generation Resource or ESR shall establish PSS settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz. The PSS settings shall be tested and tuned to ensure the PSS has appropriate damping characteristics. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(5) If an excitation system on a synchronously interconnected Generation Resource or synchronously interconnected ESR greater than 10 MW is modified or replaced after January 1, 2008, the Resource shall install a PSS, establish PSS settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz, and place the PSS in-service.

The settings shall be tested and tuned to ensure the excitation system has appropriate damping characteristics. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(6) If it is determined that a change in PSS settings or the addition of a PSS to a synchronously interconnected Generation Resource or synchronously interconnected ESR would improve overall system performance, ERCOT shall coordinate with the Resource owner to determine appropriate settings. Within 180 days of determining appropriate settings, the Resource owner shall revise the PSS setting and/or install the PSS. Any PSS setting established pursuant to this section shall be established to dampen modes with oscillations as directed by ERCOT and place the PSS in-service. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(7) At least every ten calendar years, Resource Entities shall conduct a PSS test or verify PSS performance based on operational data for the purpose of model verification on PSSs. All new synchronously interconnected Generation Resources and synchronously interconnected ESR shall conduct a PSS test within five years of the initial PSS test that was approved as part of the commissioning process. All subsequent tests shall be conducted on a ten year cycle. Additionally, if PSS equipment characteristics are modified, the Resource Entity shall conduct a performance test within 120 days of the modification. Industry accepted testing techniques shall be used for testing, measuring and calculating the modeling parameters. The test report must list the test(s) conducted and include the operational data used to verify the modeling parameters. Any models created from the test data must be a standard PSS/E dynamic model or ERCOT and TSP approved user written model. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(a) Resource Entities will provide the test data or verified dynamic models to ERCOT by submittal to the NDCRC application located on the MIS Secure Area by updating its Resource Registration information respectively.

(8) An exemption may be granted for the testing requirements listed above if the Resource on which the PSS is installed has a current ANCF, as calculated per paragraph (4) of Section 2.2.5, Automatic Voltage Regulators, of 5% or less over the most recent three calendar years preceding the planned testing calendar year. At the end of this ten year timeframe, the current average three year ANCF (for years eight, nine, and ten) will be examined by ERCOT to determine if the exemption can be declared for the next ten year period. If no longer eligible for the ANCF exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. Under certain operating conditions, ERCOT may require a ten year test even if the current average three year ANCF is below the 5% threshold.

(9) The results of PSS tests or PSS performance verification shall be supplied to ERCOT and the TSP within 30 days of a request from ERCOT.

2.2.7 Turbine Speed Governors

(1) A Governor shall be in-service whenever the Generation Resource or ESR is connected to the ERCOT System, or Settlement Only Generator (SOG) is connected to the ERCOT Transmission Grid.

(2) Generation Resources and ESRs that have not been evaluated in at least eight Frequency Measurable Events (FMEs) within 36 months shall conduct Governor performance tests within 12 months using one of the test methods or historical methods specified in Section 8, Attachment C, Turbine Governor Speed Tests. The Resource Entity shall then provide test results to ERCOT.

(3) Generation Resources and ESRs, except steam turbines of Combined Cycle Generation Resources, Settlement Only Transmission Generators (SOTGs), and Settlement Only Transmission Self-Generators (SOTSGs) shall have Governor droop characteristics and Governor Dead-Band settings no greater than those shown below in Table 1, Maximum Governor Dead-Band Settings, and Table 2, Maximum Governor Droop Settings, as defined below:

Table 1: Maximum Governor Dead-Band Settings

Resource Type	Max. Deadband
Steam Turbines with Mechanical Governors	+/- 0.034 Hz
Hydro Turbines with Mechanical Governors	+/- 0.034 Hz
All Other Generating Units/Generating Facilities/ESRs	+/- 0.017 Hz
Controllable Load Resources (CLRs)	+/- 0.036 Hz

Table 2: Maximum Governor Droop Settings

Generator Type	Max. Droop % Setting
Combustion Turbine (Combined Cycle)	4%
All Other Generating Units/Generating Facilities/ESRs/CLRs	5%

(4) If ERCOT determines that ERCOT System reliability would be enhanced, for a defined period of time, ERCOT may direct Wind-powered Generation Resources (WGRs) under the control of a Remedial Action Scheme (RAS) to limit power increases due to frequency if there is risk of a RAS operation due to a low frequency FME.

2.2.8 Performance/Disturbance/Compliance Analysis

(1) Performance/Disturbance/Compliance analysis shall be performed by ERCOT for the purpose of ensuring conformance with the Protocols and Operating Guides. All Generation Resources, ESRs, SOTGs, SOTSGs, and CLRs, except nuclear-powered Resources or WGRs with a permanent exemption approved by ERCOT, must respond to frequency disturbances with a Governor droop as specified in Section 2.2.7, Turbine Speed Governors. Each Generation Resource, ESR, SOTG, SOTSG, and CLR based on

participation in at least eight FMEs, shall meet a minimum 12-month rolling average initial Primary Frequency Response performance and sustained Primary Frequency Response performance of 0.75 as calculated in Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response. When assessing conformance with the Protocols and Operating Guides, ERCOT shall evaluate the annual rolling average and may exclude from the performance analysis Generation Resources, ESRs, SOTGs, SOTSGs, or CLRs in accordance with, but not limited to, the following conditions:

(a) Operating within the larger of five MW or 2% of the High Sustained Limit (HSL) or the maximum capacity for low frequency disturbances;

(b) Operating within the larger of five MW or 2% of the HSL or the maximum capacity above the LSL for high frequency disturbances;

(c) For an ESR, while discharging, if operating within the larger of 3 MW or 2% of the Maximum Operating Discharge Power Limit for low frequency disturbances;

(d) For an ESR, while charging, if operating within the larger of 3 MW or 2% of the Maximum Operating Charge Power Limit for high frequency disturbances;

(e) For any Generation Resource carrying power augmentation, the maximum capacity will be computed as the HSL minus Non-Frequency Responsive Capacity (NFRC); or

(f) Having a technical or physical limitation filed with the ERCOT client representative and approved by ERCOT.

[NOGRR263: Replace paragraph (1) above with the following upon system implementation of NPRR1244:]

(1) Performance/Disturbance/Compliance analysis shall be performed by ERCOT for the purpose of ensuring conformance with the Protocols and Operating Guides. All Generation Resources, ESRs, CLRs that are capable of providing Primary Frequency Response, SOTGs, and SOTSGs, except nuclear-powered Resources or WGRs with a permanent exemption approved by ERCOT, must respond to frequency disturbances with a Governor droop as specified in Section 2.2.7, Turbine Speed Governors. Each Generation Resource, ESR, CLR qualified for Regulation Service and/or RRS, SOTG, and SOTSG based on participation in at least eight FMEs, shall meet a minimum 12-month rolling average initial Primary Frequency Response performance and sustained Primary Frequency Response performance of 0.75 as calculated in Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response. When assessing conformance with the Protocols and Operating Guides, ERCOT shall evaluate the annual rolling average and may exclude from the performance analysis Generation Resources, ESRs, CLRs qualified for Regulation Service and/or RRS, SOTGs, or SOTSGs in accordance with, but not limited to, the following conditions:

(a) Operating within the larger of five MW or 2% of the High Sustained Limit (HSL) or the maximum capacity for low frequency disturbances;

(b) Operating within the larger of five MW or 2% of the HSL or the maximum capacity above the LSL for high frequency disturbances;

(c) For an ESR, while discharging, if operating within the larger of 3 MW or 2% of the Maximum Operating Discharge Power Limit for low frequency disturbances;

(d) For an ESR, while charging, if operating within the larger of 3 MW or 2% of the Maximum Operating Charge Power Limit for high frequency disturbances;

(e) For any Generation Resource carrying power augmentation, the maximum capacity will be computed as the HSL minus Non-Frequency Responsive Capacity (NFRC); or

(f) Having a technical or physical limitation filed with the ERCOT client representative and approved by ERCOT.

(2) Market Participants shall request an exemption from, or correction of, performance during an FME within 30 days of the MIS posting date of the "Initial and Sustained Frequency Response Unit Performance" report.

(3) ERCOT will, on an as needed basis, utilize the Performance, Disturbance, Compliance Working Group (PDCWG) as a technical resource in providing input for types of technical or physical limitations that may be approved by ERCOT.

(4) ERCOT shall make a regular report on selected system disturbances, documenting the response of individual Generation Resources, ESRs, and CLRs. In addition, Resource Entities, QSEs, and individual members of the PDCWG are encouraged to work within their respective companies to enhance the performance of individual Generation Resource's, ESR's, or CLR's control systems through application of the results of the PDCWG studies.

2.2.9 Time Error and Time Synchronization

2.2.9.1 Time Error

(1) Sustained frequency deviations from scheduled frequency result in Time Error. Time Error will be monitored and controlled in ERCOT as follows:

(a) Time Error Monitoring - ERCOT will monitor accumulated Time Error and initiate time corrections. The instantaneous Time Error is available to all QSEs on the ERCOT website.

(b) Time Error Correction - ERCOT may conduct Time Error correction at any time. However, ERCOT must promptly initiate Time Error correction if the Time Error exceeds +/- 30 seconds, unless operational circumstances require otherwise. ERCOT will initiate and terminate Time Error correction via Hotline call to QSEs representing Resources. The call initiating Time Error correction will include the frequency offset (- 0.02 Hz for fast and + 0.02 Hz for slow) and the start time. The Time Error correction may end when:

(i) The Time Error is within +/- 0.5 seconds of the target reference;

(ii) System events mandate termination;

(iii) The period of correction reaches five hours; or

(iv) After any hour without at least a 0.5 second error reduction.

2.2.9.2 Time Synchronization

(1) To promote accurate data reporting during an Energy Emergency Alert (EEA) and other system events, and to ensure transaction schedules are simultaneous, all QSEs and TOs, and ERCOT will maintain their control system time within ±3 seconds of the National Bureau of Standards (NBS) time signal. The NBS time signal shall set the time standard for ERCOT. ERCOT, QSEs and TOs are required to employ clocks, voice and data recording systems that synchronize automatically with the NBS on at least a weekly basis.

2.2.10 Generation Resource and Energy Storage Resource Response Time Requirements

(1) All Generation Resources and ESRs providing Voltage Support Service (VSS) as described in Protocol Section 3.15, Voltage Support, shall maintain the necessary procedures and processes plus communications, telemetry, remote control, automation, and staffing in order to normally comply with the response times listed below when a VSS Dispatch Instruction or a TO Voltage Set Point instruction, as described in Protocol Section 6.5.7.7, Voltage Support Service, is given. Compliance is based upon normal operating conditions where VSS Dispatch Instructions respect all equipment operating limits and other restrictions that are periodically placed on equipment. The response time to a VSS Dispatch Instruction or a TO Voltage Set Point instruction shall commence with the successful receipt by the QSE, Generation Resource, or ESR either through a verbal or telemetered instruction.

(2) A Resource Entity, TO, or QSE is not required to comply with a VSS Dispatch Instruction or Voltage Set Point instruction if compliance with such an instruction is impossible due to either a Force Majeure Event or one or more of the conditions described in paragraphs (1) and (2) of Protocol Section 6.5.7.9, Compliance with Dispatch Instructions. In the event compliance with an instruction is precluded under this paragraph:

(a) An affected Resource Entity shall, as soon as practicable, but not longer than 15 minutes from receipt of the instruction by the Resource Entity, notify its QSE, and the Resource Entity or its QSE shall, as soon as practicable, notify the Entity issuing the instruction; and

(b) An affected TO shall, as soon as practicable, but not longer than 15 minutes from notification from the Resource Entity or its QSE, notify ERCOT.

(3) The required VSS response times for Generation Resources and ESRs are:

(a) For automatically switchable static VAr capable devices, when voltage or reactive measurements at the POIB are outside of the Voltage Set Point tolerance band identified in paragraph (4) of Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements; then the response must be fully deployed in no more than five minutes. If a TO and a Resource Entity have determined that a longer response time is appropriate and have entered into a written agreement reflecting that response time, then the Generation Resource or ESR shall be required to comply with that agreed response time so long as it does not exceed ten minutes.

(b) Response to a TO Voltage Set Point instruction shall be completed in no more than five minutes from receipt of the instruction.

(c) Response to a VSS Dispatch Instruction that requires a change to the real power output of the Generation Resource or ESR shall be completed as soon as practicable.

(4) Shutting down and disconnecting Generation Resources or ESRs from the ERCOT System:

(a) On-Line Generation Resources or ESRs must be able to commence their shutdown sequence within five minutes of receipt of a Dispatch Instruction from ERCOT. Nuclear-fueled Generation Resources shall comply with the procedural requirements of the Nuclear Regulatory Commission (NRC) when receiving Dispatch Instructions from ERCOT to disconnect the Generation Resource from the ERCOT Transmission Grid. Additionally, Distribution Generation Resources (DGRs) or Distribution Energy Storage Resources (DESRs) must be able to shut down their generators in a timeframe that meets the requirements of their Distribution Service Provider (DSP). Once disconnected from the ERCOT System, the QSE shall update the DGR or DESR's Current Operating Plan (COP) as soon as practicable of plans to reconnect to the ERCOT System.

(b) If the ERCOT Transmission Grid condition requires breaker or switch operations to disconnect a non-MW producing Generation Resource or ESR from the system, such operations shall be completed as soon as practicable, but no longer than 15 minutes of the receipt of a Dispatch Instruction from ERCOT. Once disconnected from the ERCOT Transmission Grid, a Generation Resource or ESR shall complete as soon as practicable, but no longer than 15 minutes, the required switching to return the system to a normal configuration except for nuclear-fueled Generation Resources, which shall comply with the procedural requirements of the NRC when receiving Dispatch Instructions from ERCOT to disconnect the Generation Resource from the ERCOT Transmission Grid.

2.3 Ancillary Services

(1) The types of Ancillary Services required by ERCOT are described below:

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Regulation Down Service (Reg-Down) and Regulation Up Service (Reg-Up) (for Generation Resources and Energy Storage Resources (ESRs)) ***Reference: Protocol Section 2, Definitions and Acronyms***	Resource capacity provided by a Qualified Scheduling Entity (QSE) from a specific Generation Resource or ESR to control frequency within the system which is controlled second by second, normally by an Automatic Generation Control (AGC) system.	a. Reg-Down energy is a Resource-specific deployment to increase or decrease generation at a level below the Generation Resource's or ESR's Base Point in response to a change in system frequency. b. Reg-Up energy is a Resource-specific deployment to increase or decrease generation at a level above the Generation Resource's or ESR's Base Point in response to a change in system frequency.
Reg-Down and Reg-Up (for Load Resource) ***Reference: Protocol Section 2***	Load Resource capacity provided by a QSE from a specific Load Resource to control frequency within the system.	a. Reg-Down is a Resource-specific deployment to increase or decrease Load below the Load Resource's Maximum Power Consumption (MPC) limit in response to a change in system frequency. b. Reg-Up is a Resource-specific deployment to increase or decrease Load above the Load Resource's Low Power Consumption (LPC) limit in response to a change in system frequency.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Responsive Reserve (RRS) ***Reference: Protocol Section 2***	Operating reserves on Generation Resources, ESRs, Load Resources, and Resources capable of providing Fast Frequency Response (FFR) maintained by ERCOT to help control the frequency of the system. RRS on Generation Resources, ESRs, and Controllable Load Resources (CLRs) can be used as energy during an Energy Emergency Alert (EEA) event.	RRS may only be deployed as follows: a. Through automatic Governor action or under-frequency relay in response to frequency deviations; b. By electronic signal from ERCOT in response to the need; and c. As ordered by an ERCOT Operator during an EEA or other emergencies.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
ERCOT Contingency Reserve Service (ECRS) ***Reference: Protocol Section 2***	a. Off-Line Generation Resource or ESR capacity, or reserved capacity from On-Line Generation Resources or ESRs, capable of being ramped to a specified output level within ten minutes and operating at a specified output for at least one hour. b. CLRs dispatchable by Security-Constrained Economic Dispatch (SCED) that are capable of ramping to an ERCOT-instructed consumption level within ten minutes and consuming at the ERCOT-instructed level for at least one hour. c. Load Resources that are not CLRs and may or may not be controlled by under-frequency relay. Load Resources that are not CLRs providing ECRS must be capable of reducing Load in response to an Extensible Markup Language (XML) Dispatch Instruction within ten minutes and remain deployed until recalled by ERCOT.	Deployed in response to loss-of-Resource contingencies, Load forecasting error, or other contingency events on the system. See Protocol Section 6.5.7.6.2.4, Deployment and Recall of ERCOT Contingency Reserve Service.
Non-Spinning Reserve (Non-Spin) Service ***Reference: Protocol Section 2***	a. Off-Line Generation Resource or ESR capacity, or reserved capacity from On-Line Generation Resources or ESRs, capable of being ramped to a specified output level within 30 minutes and operating at	Deployed in response to loss-of-Resource contingencies, Load forecasting error, or other contingency events on the system. See Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
	a specified output for at least four consecutive hours. b. CLRs that are capable of ramping to an ERCOT-instructed consumption level within 30 minutes and consuming at the ERCOT-instructed level for at least four consecutive hours. c. Load Resources that are not CLRs and that are not controlled by under-frequency relay. Load Resources that are not CLRs providing Non-Spin must be capable of reducing Load in response to an XML Dispatch Instruction within 30 minutes and remain deployed until recalled by ERCOT.	
Voltage Support Service (VSS) ***Reference: Protocol Section 3.15, Voltage Support***	Reactive capability of a Generation Resource or ESR that is required to maintain transmission and distribution voltages on the ERCOT Transmission Grid within acceptable limits. All Generation Resources and ESRs with a gross rating greater than 20 MVA shall provide VSS.	Direct the scheduling of VSS by providing Voltage Profiles at the Point of Interconnection Bus (POIB). The Generation Resource or ESR is obligated to maintain the published Voltage Profile within its Corrected Unit Reactive Limit (CURL).
Black Start Service (BSS) ***Reference: Protocol Section 3.14.2, Black Start***	The provision of Generation Resources under a Black Start Agreement, which are capable of self-starting without support from within ERCOT in the event of a Partial Blackout or Blackout.	Provide emergency Dispatch Instructions to begin restoration to a secure operating state after a Partial Blackout or Blackout.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Reliability Must-Run (RMR) Service ***Reference: Protocol Section 3.14.1, Reliability Must Run***	The provision of Generation Resource capacity and energy under an RMR Agreement.	Enter into contractual agreements to retain units required for reliable operations. Direct the operation of those units that otherwise would not operate and that are necessary to provide reliable operations.

2.3.1 Responsive Reserve

2.3.1.1 Obligation

(1) ERCOT operating reserve requirements are more restrictive than North American Electric Reliability Corporation (NERC) Reliability Standards. The RRS obligation is a minimum of 2300 MW. The amount of RRS procured may be adjusted as described in ERCOT Methodologies for Determining Ancillary Service Requirements or if ERCOT determines a reliability need for additional Ancillary Service Resources.

2.3.1.2 Additional Operational Details for Responsive Reserve Providers

(1) ERCOT shall specify the minimum amount of RRS provided by Generation Resources as outlined in Section 2.3.1.2.1, Limit on Resources Providing RRS Using Primary Frequency Response. QSE's Generation Resources providing RRS must be On-Line, immediately responsive to system frequency deviations.

(2) RRS provided by a QSE shall meet the requirements as defined in paragraph (3) of Protocol Section 3.18, Resource Limits in Providing Ancillary Service.

(3) ERCOT shall issue Dispatch Instructions for RRS through Inter-Control Center Communications Protocol (ICCP) to a QSE representing a Generation Resource in synchronous condenser fast-response mode that is responding to a Frequency Measurable Event (FME) at or below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18, or under manual deployment when system frequency does not go below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18. Dispatch Instructions under this section shall only occur during scarcity conditions, as specified in Protocol Section 6.5.9.4.2, EEA Levels, or in an attempt to recover frequency to meet NERC Standards.

(4) Unless ERCOT issues a recall instruction for the RRS deployed via ICCP, the QSE of the Generation Resource operating in synchronous condenser fast-response mode may

contact ERCOT to determine if it is allowed to recall and reset the individual unit(s) to the synchronous condenser fast-response mode.

(5) ERCOT, at its sole discretion, may request that the Generation Resource operating in synchronous condenser fast-response mode remain On-Line and generating after an initial deployment. The request to remain On-Line and generating after an initial deployment may not exceed 30 minutes per deployment for each frequency deviation or event nor shall such request exceed two hours per a consecutive 12-hour period in aggregate unless ERCOT has declared an EEA.

(6) Load Resources providing RRS must be either a CLR qualified for SCED and capable of providing Primary Frequency Response or a Load Resource controlled by high-set under-frequency relays for automatic interruption. For eligibility to participate as a RRS provider, reference Protocol Section 8.1.1.2.1.2, Responsive Reserve Qualification. Load Resources controlled by high-set under-frequency relays shall also complete the following requirements:

(a) The under-frequency relay must have a delay of no more than 20 cycles (or 0.33 seconds for relays that do not count cycles). Total time from the time frequency first decays to a value low enough to initiate action of the under frequency relay(s) to the time Load is interrupted should be no more than 30 cycles, including all relay and breaker operating times;

(b) The initiation setting of the under-frequency relay shall not be any lower than 59.7 Hz; and

(c) The Load Resource must be able to remain interrupted during actual event until replaced by other net dependable capability. In no case may interrupted Load be restored to service without the approval of an ERCOT operator.

(7) To become and remain fully qualified as a provider of RRS, the Load Resource shall complete the requirements above and the following:

(a) Pass simulated or actual testing according to ERCOT procedures; and

(b) Perform verification testing as described in Section 8, Attachment G, Load Resource Tests.

(8) Generation Resource operating in synchronous condenser fast-response mode – Modes of RRS and/or ECRS that will be counted:

(a) Synchronous condenser fast response mode **-** described in item (3)(b) or (4)(c) of Protocol Section 3.18;

(b) Generation MW mode **-** For any Generation Resource with a 5% droop setting operating as a generator, the amount of RRS provided is dependent upon the verified droop characteristics of the Resource;

(c) Synchronous Condenser Mode in "Manual" Dispatch Mode - Units will supply MWs based on operator action within the ten-minute Protocol requirement for supplying RRS or ECRS. Once deployed these units are frequency responsive; and

(d) A Real-Time signal of the MW capacity of units being operated in any of the synchronous condenser modes is telemetered to ERCOT.

(9) Each Resource seeking RRS qualification as a Resource capable of providing FFR must be On-Line and shall also meet the following requirements:

(a) The total time from the time frequency first decays to a value low enough to initiate action up to the time when full Ancillary Service Resource Responsibility for RRS is delivered should be no more than 15 cycles, including all relay and breaker operating times;

(b) The initiation setting of the under-frequency relay or similar trigger mechanism shall not be any lower than 59.85 Hz;

(c) A Resource must demonstrate its ability to sustain the scheduled level of deployment for at least 15 minutes at a minimum level of 95% but not more than a maximum level of 110% of the MW capacity for which the Resource seeks qualification for FFR; and

(d) Resource providing FFR shall be capable of measuring and recording ERCOT Frequency (Hz) and MW output with a resolution of no less than 32 samples per second.

(10) Control performance during periods in which ERCOT has deployed FFR shall be based on the requirements below:

(a) For any FFR deployment event, ERCOT will collect the following data:

(i) High speed event data from Resources that are not deployed via breaker action;

(ii) High speed event data from the recorders at ERCOT's primary and back-up facilities;

(iii) High speed event data from phasor measurement units available to ERCOT;

(iv) Telemetry data for all Resources providing FFR during the event; and

(v) Recording of ERCOT frequency (Hz) and MW output with a resolution of no less than 32 samples per second.

(b) The performance of a Load Resource providing FFR in response to an RRS Dispatch Instruction shall be determined by subtracting the Load Resource's actual Load response from the average of the telemetered net real power consumption values for the five minutes preceding the Dispatch Instruction ("meter before / meter after"). The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.

(c) For an FFR deployment event triggered by an under-frequency event (frequency at or below 59.85 Hz). ERCOT will use the collected data to determine if the following requirements were met:

(i) The total time from the time frequency first decays to a value low enough to initiate action up to the time when full Ancillary Service award for RRS is delivered should be no more than 15 cycles, including all relay and breaker operating times;

(ii) The Resource deployed 95% to 110% of its Ancillary Service award for RRS in 15 cycles after the frequency reached 59.85 Hz;

(iii) The SCED-dispatchable Resource sustained 95% to 110% of its Ancillary Service award for RRS;

(iv) The non-CLR providing FFR sustained 95% to 110% of its Ancillary Service award for RRS for the duration of the sustained response period, defined as 15 minutes or until the time of recall instruction from ERCOT, whichever occurred first;

(v) Upon completion of deployment, ERCOT will issue a recall instruction to a Resource providing FFR. Once the recall instruction is issued to Resources providing FFR, the Resource shall continue following its Updated Desired Set Point (UDSP). A Load Resource that is controlled by a high-set under-frequency relay and is providing FFR may only withdraw energy from the grid after the frequency has recovered to 60 Hz and Physical Responsive Capability (PRC) is above 2,500 MW, or if instructed to do so by ERCOT.

(d) For an FFR deployment of non-CLRs through a Verbal Dispatch Instruction (VDI), in addition to the data listed in paragraph (a) above, ERCOT will collect a voice recording of the VDI to document the time of the instruction. The official start of the ramp period for the FFR deployment is the end of the ERCOT Operator's acknowledgement that the read back of the instruction was correct. ERCOT will use the collected data to determine if the following requirements were met:

(i) The Resource deployed 95% to 110% of its Ancillary Service award for RRS within ten minutes after the start of the ramp period;

(ii) The Resource sustained 95% to 110% of its Ancillary Service award for RRS for the duration of the sustained response period, defined as 15 minutes or until the time of recall instruction from ERCOT, whichever occurred first;

(iii) Upon completion of deployment, ERCOT will issue a recall instruction to a Resource providing FFR. A Load Resource that is controlled by a high-set under-frequency relay and is providing FFR may only withdraw energy from the grid after the frequency has recovered to 60 Hz and PRC is above 2,500 MW, or if instructed to do so by ERCOT.

(11) If a failure occurs at the QSE or sub-QSE level, as part of any compliance review ERCOT shall identify the individual Resource(s) responsible for the failure. QSEs representing Resources providing FFR will have an opportunity to provide ERCOT with site-specific high resolution data (at least 32 samples per second) for further analysis. Regardless of the QSE's or sub-QSE level performance, ERCOT may require any individual Resource that fails to meet its FFR performance criteria to submit a corrective action plan and may suspend a Resource's qualification to provide FFR for a pattern of non-performance.

2.3.1.2.1 Limit on Resources Providing RRS Using Primary Frequency Response

(1) ERCOT shall establish MW limits on individual Resource's ability to provide RRS using Primary Frequency Response. The MW limit shall be based on Resource performance during FMEs and actual tests.

(2) The default maximum MW limit of Primary Frequency Response shall be set to 20% of its Maximum Droop Response Range (MDRR) for any newly qualified Resource not yet evaluated per Section 8, Attachment N, Procedure for Calculating RRS MW Limits for Individual Resources to Provide RRS Using Primary Frequency Response, for measuring actual performance.

(3) A Private Use Network with a registered Resource may use the gross High Sustained Limit (HSL) for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide.

2.3.2 Non-Spinning Reserve Service

2.3.2.1 Additional Operational Details for Non-Spinning Reserve Service Providers

(1) Non-Spin Service Generation Resource providers, including MW from power augmentation, must be capable of being synchronized and ramped to a specified output level within 30 minutes of notification of deployment and run at a specified output level for at least four consecutive hours, as specified in item (1)(a) of Protocol Section 3.17.3, Non-Spinning Reserve Service.

(2) Non-Spin CLR providers must be capable of ramping to an ERCOT-instructed consumption level within 30 minutes and consuming at the ERCOT-instructed level for at least four consecutive hours, as specified in item (1)(b) of Protocol Section 3.17.3.

(3) A Load Resource that is not a CLR providing Non-Spin must be capable of reducing Load based on an XML Dispatch Instruction issued by ERCOT within 30 minutes and maintaining that deployment until recalled.

(4) To become provisionally qualified as a provider of Non-Spin, a Load Resource shall complete the following requirements:

(a) Register as a Load Resource with ERCOT;

(b) Complete asset registration of the Load Resource;

(c) Provide ERCOT the appropriate Non-Spinning Load affidavit;

(d) Test to verify appropriate voice communications are in place for VDIs by ERCOT;

(e) Provide telemetry through the QSE to ERCOT in accordance with all applicable requirements set forth in paragraph (5) of Protocol Section 6.5.5.2, Operational Data Requirements; and

(f) Be able to consume at an ERCOT-instructed level during an ERCOT deployment based on the applicable duration requirements specified in Section 2.3, Ancillary Services.

(5) To become and remain fully qualified as a provider of Non-Spin, the Load Resource shall complete all the requirements for provisional qualification identified above and the following:

(a) Respond successfully to an actual ERCOT deployment or pass simulated or actual testing according to ERCOT's Procedure; and

(b) Perform verification testing as described in Section 8, Attachment G, Load Resource Tests.

2.3.3 ERCOT Contingency Reserve Service

2.3.3.1 Additional Operational Details for ERCOT Contingency Reserve Service (ECRS) Providers

(1) Generation Resources providing ECRS must be capable of being synchronized and ramped to a specified output level within ten minutes of notification of deployment and run at a specified output level for at least one hour.

(2) CLR providing ECRS must be capable of ramping to an ERCOT-instructed consumption level within ten minutes and consuming at the ERCOT-instructed level for at least one hour.

(3) To become provisionally qualified as a provider of ECRS, a CLR shall complete the following requirements:

(a) Register as a CLR with ERCOT;

(b) Provide ERCOT the ECRS Load affidavit;

(c) Test to verify primary and alternative voice communications are in place for VDIs by ERCOT;

(d) Provide telemetry through the QSE to ERCOT in accordance with all applicable requirements set forth in paragraph (5) of Protocol Section 6.5.5.2, Operational Data Requirements; and

(e) Be able to maintain consumption at an ERCOT-instructed level during an ERCOT-instructed test for the entire duration of the test period.

(4) To become and remain fully qualified as a provider of ECRS, the CLR shall complete all the requirements for provisional qualification identified above and the following:

(a) Respond successfully to an actual ERCOT deployment or pass actual testing according to ERCOT's Procedure; and

(b) Perform verification testing as described in Section 8, Attachment G, Load Resource Tests.

(5) The total amount of ECRS that Load Resources other than CLRs may provide shall not exceed 50% of the total ERCOT-wide ECRS requirement. A Load Resource must be loaded and capable of unloading the scheduled amount of ECRS within ten minutes of instruction by ERCOT or be interrupted by action of under-frequency relays.

(a) Load Resources that are providing ECRS are not required to be controlled by high-set under-frequency relays.

(b) Load Resources controlled by high-set under-frequency relays and providing ECRS shall meet the relay setting requirement stated in paragraph (6) of Section 2.3.1.2, Additional Operational Details for Responsive Reserve Providers.

(6) ERCOT shall deploy ECRS to meet NERC Reliability Standards and other performance criteria as specified in these Operating Guides and the Protocols by Dispatch Instruction for ECRS through ICCP to a QSE representing a Generation Resource in synchronous condenser fast-response mode that is responding to an FME at or below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18, or under manual deployment when system frequency does not go below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18. Dispatch Instructions under this section shall only occur

during scarcity conditions, as specified in Protocol Section 6.5.9.4.2, EEA Levels, or in an attempt to recover frequency to meet NERC Standards; and/or Dispatch Instruction for deployment of Load Resources energy via electronic Messaging System.

2.4 Outage Coordination

(1) For Outage coordination details, reference Protocol Section 3.1, Outage Coordination and the ERCOT Market Information System (MIS) Secure Area.

2.5 Reliability Unit Commitment

2.5.1 Criteria for Removing Contingencies from the Reliability Unit Commitment Analyses

(1) ERCOT shall remove contingencies from the Reliability Unit Commitment (RUC) analysis when:

(a) The contingency is known to produce post-contingency results that are incorrect; or

(b) The contingency is known to produce a non-convergent contingency result which may cause the RUC process to fail.

2.6 Requirements for Under-Frequency and Over-Frequency Relaying

2.6.1 Automatic Firm Load Shedding

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph, unless provisions specified in Section 4.5.3.3, EEA Levels, are required to meet ERCOT operating instructions for manual Load shed. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in Table 1, Standard UFLS Stages, below. TOs may, but are not required to, provide supplemental anti-stall under-frequency Load relief in the amounts described in Table 2, Supplemental Anti-Stall UFLS Stages, below. If the TOs provide supplemental anti-stall under-frequency Load relief, the under-frequency relays shall be set to use the frequency thresholds and time delays described in Table 2. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, when the ERCOT frequency drops to the 59.5 Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.

[NOGRR226: Replace paragraph (1) above with the following upon system implementation but no earlier than October 1, 2026:]

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph, unless provisions specified in Section 4.5.3.3, EEA Levels, are required to meet ERCOT operating instructions for manual Load shed. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in Table 1, Standard UFLS Stages, and Table 2, Supplemental/Anti-Stall UFLS Stages, below. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, when the ERCOT frequency drops to the 59.5 Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.

Table 1: Standard UFLS Stages

Frequency Threshold	TO Load Relief	Delay to Trip
59.3 Hz	At least 5% of the TO Load	No more than 30 cycles
59.1 Hz	A total of at least 5% of the TO Load	No more than 30 cycles
58.9 Hz	A total of at least 15% of the TO Load	No more than 30 cycles
58.7 Hz	A total of at least 15% of the TO Load	No more than 30 cycles
58.5 Hz	A total of at least 25% of the TO Load	No more than 30 cycles

[NOGRR247: Replace Table 1 above with the following upon system implementation but no earlier than October 1, 2026:]

Frequency Threshold	TO Load Relief	Delay to Trip
59.3 Hz	At least 5% of the TO Load	At least six cycles but no more than 30 cycles
59.1 Hz	A total of at least 10% of the TO Load	At least six cycles but no more than 30 cycles

58.9 Hz	A total of at least 15% of the TO Load	At least six cycles but no more than 30 cycles
58.7 Hz	A total of at least 20% of the TO Load	At least six cycles but no more than 30 cycles
58.5 Hz	A total of at least 25% of the TO Load	At least six cycles but no more than 30 cycles

Table 2: Supplemental/Anti-Stall UFLS Stages

Frequency Threshold	**TO Load Relief**	**Delay to Trip**
59.5 Hz	At least 1.5% of the TO Load	90 seconds
59.5 Hz	A total of at least 3.0% of the TO Load	120 seconds
59.5 Hz	A total of at least 4.5% of the TO Load	150 seconds

(2) ERCOT will, prior to the peak each year, survey each TO's compliance with the automatic Load shedding requirements described in paragraph (1) above, and report its findings to the Technical Advisory Committee (TAC). For purposes of determining a TO's compliance with this annual survey requirement, TO Load will be the total amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, at the specified time of the survey. The TO shall identify those circuits armed with under-frequency relays, the corresponding amount of Load, and identify the frequency threshold. A TO shall not equip the entirety of its Load shed obligation in any one tier, and should endeavor to shed in controlled amounts that equal the difference between the TO Load relief required for each tier. If ERCOT identifies potential reliability issues related to distribution of Load shed across the tiers, ERCOT may require the TO to redistribute Load relief closer to the minimum amount required after submitting ERCOT's proposal to redistribute Load relief to the TO and considering any comments submitted by the TO regarding the proposal. Compliance with this annual survey does not excuse the TO from compliance with the requirements of paragraph (1) above in an actual frequency event. To assist TOs, ERCOT will provide the TO's inventory, including substation and capacity amounts, of registered Load Resources in its area within ten Business Days of receiving a request in writing from a TO.

(3) A TO may meet the Load relief requirements of the Supplemental anti-stall UFLS stages by utilizing Load that would otherwise be utilized to meet the 59.1 Hz, 58.9 Hz, 58.7 Hz, and 58.5 Hz standard UFLS stages. In this circumstance, the TO's Load relief responsibility at the 59.1 Hz, 58.9 Hz, 58.7 Hz, and 58.5 Hz standard UFLS stages is reduced by the amount of Load already shed in the supplemental anti-stall UFLS stages.

A TO may not meet the Load relief requirements of the supplemental anti-stall UFLS stages by utilizing Load that the TO needs to meet the 59.3 Hz standard UFLS stages.

(4) Additional under-frequency relays may be installed on Transmission Facilities with the approval of ERCOT provided the relays are set at 58.0 Hz or below, are not directional, and have at least 2.0 seconds time delay. A DSP may by mutual agreement arrange to have all or part of its automatic Load shedding requirement performed by another entity. ERCOT will be notified and provided with the details of any such arrangement prior to implementation.

(5) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard to which Load Serving Entity (LSE) serves the customer. DSPs shall ensure that Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) are connected to circuits that are not subject to disconnection during UFLS events, except as permitted by Protocol Section 3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs). DSPs shall ensure that the under-frequency relays connected to each Load will operate with a fixed time delay as specified in paragraph (1) above. Total time from the time when a sustained under-frequency condition first reaches one of the values specified above to the time Load is interrupted shall be no more than the maximum fixed time delay specified in paragraph (1) above plus 10 cycles, including all relay and breaker operating times, and no less than any applicable minimum fixed time delay specified in paragraph (1) above. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

[NOGRR250: Replace paragraph (5) above with the following upon system implementation of NPRR1171:]

(5) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard to which Load Serving Entity (LSE) serves the customer. DSPs shall ensure that the under-frequency relays connected to each Load will operate with a fixed time delay as specified in paragraph (1) above. Total time from the time when a sustained under-frequency condition first reaches one of the values specified above to the time Load is interrupted shall be no more than the maximum fixed time delay specified in paragraph (1) above plus 10 cycles, including all relay and breaker operating times, and no less than any applicable minimum fixed time delay specified in paragraph (1) above. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

(6) If a loss of Load occurs due to the operation of under-frequency relays, a DSP or its designee may rotate the physical Load interrupted to minimize the duration of interruption experienced by individual Customers or to restore the availability of under-frequency Load-shedding capability. In no event shall the initial total amount of Load without service be decreased without the approval of ERCOT. TOs, in coordination with DSPs, shall make every reasonable attempt to restore Load, either by automatic or manual means, to preserve system integrity. Restoration of any Load shed by UFLS systems, including supplemental anti-stall UFLS Load, shall be coordinated with ERCOT by the TO. In the event frequency drops below any of the frequency thresholds specified in the tables in paragraph (1) above, and a TO's UFLS relays that previously activated as a result of reaching that same frequency threshold have not been restored since the previous excursion, the Load on the feeders controlled by those relays shall be counted toward the TO's satisfaction of the percentages in paragraph (1) above for that subsequent frequency excursion.

2.6.2 Frequency Ride-Through Requirements for Generation Resources and Energy Storage Resources

(1) Except for Generation Resources and Energy Storage Resources (ESRs) subject to Sections 2.6.2.1, Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, or 2.6.2.2, Frequency Ride-Through Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs), if under-frequency relays are installed and activated to trip the Generation Resource or ESR, these relays shall perform such that the automatic removal of the Resource from the ERCOT System meets or exceeds the following requirements:

Frequency Range	Delay to Trip
Above 59.4 Hz	No automatic tripping (continuous operation)
Above 58.4 Hz up to and including 59.4 Hz	Not less than 9 minutes
Above 58.0 Hz up to and including 58.4 Hz	Not less than 30 seconds
Above 57.5 Hz up to and including 58.0 Hz	Not less than 2 seconds
57.5 Hz or below	No time delay required

(2) Except for Generation Resources subject to Sections 2.6.2.1 or 2.6.2.2, if over-frequency relays are installed and activated to trip the Resource, the Resource shall perform such that the automatic removal of the Resource from the ERCOT System meets or exceeds the following requirements:

Frequency Range	Delay to Trip

Below 60.6 Hz down to and including 60 Hz	No automatic tripping (continuous operation)
Below 61.6 Hz down to and including 60.6 Hz	Not less than 9 minutes
Below 61.8 Hz down to and including 61.6 Hz	Not less than 30 seconds
61.8 Hz or above	No time delay required

(3) If frequency protection schemes are installed and activated to trip a Generation Resource or ESR, they shall use filtered quantities or add sufficient time delays to prevent misoperations while providing the desired equipment protection. Protection schemes shall not trip a Generation Resource or ESR based on an instantaneous frequency measurement.

(4) This Section shall not affect the Resource Entity's responsibility to protect Generation Resources or ESRs from damaging operating conditions. The Resource Entity for a Generation Resource or ESR subject to paragraphs (1) and (2) above that is unable to remain reliably connected to the ERCOT System as set forth in paragraphs (1) and (2), shall immediately provide to ERCOT the reason(s) for the Resource's limitation, including available study results or manufacturer recommendations, and the Resource's frequency ride-through capability in the format shown in the tables in paragraphs (1) and (2) above.

2.6.2.1 Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs

(1) This Section applies to all IBRs, Type 1 WGRs and Type 2 WGRs connected to the ERCOT Transmission Grid. Such Resources shall ride through the frequency conditions at the Resource's Point of Interconnection Bus (POIB) specified in the following table:

Frequency (f) in (Hz)	Minimum Ride-Through Time (seconds)
f > 61.8	May ride-through or trip
61.6 < f ≤ 61.8	299
61.2 < f ≤ 61.6	540
58.8 ≤ f ≤ 61.2	continuous
58.4 ≤ f < 58.8	540
57.0 ≤ f < 58.4	299
f < 57.0	May ride-through or trip

(2) Nothing in paragraph (1) above shall be interpreted to require an IBR, Type 1 WGR or Type 2 WGR to trip for frequency conditions beyond those for which ride-through is required.

(3) If protection systems (including, but not limited to protection for over-/under-frequency, rate-of-change-of-frequency, anti-islanding, and phase angle jump) are installed and

activated to trip the IBR, Type 1 WGR or Type 2 WGR, they shall enable the Resource to ride through frequency conditions beyond those defined in paragraph (1) above to the maximum level the equipment allows.

(4) An IBR, Type 1 WGR or Type 2 WGR shall inject electric current when required to ride-through frequency conditions. Except when caused by reductions associated with intermittent primary energy source availability (e.g., wind speed or solar irradiance), an IBR, Type 1 WGR or Type 2 WGR shall not reduce active current injection during frequency conditions requiring ride-through unless allowed pursuant to paragraph (4) of Section 2.9.1.1, Preferred Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), or paragraph (4) of Section 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, or to provide appropriate frequency response.

(5) IBR, Type 1 WGR and Type 2 WGR plant controls, turbine controls and/or inverter controls shall not disconnect the plant or any individual inverter/turbine, or prevent current exchange between the Resource and the ERCOT Transmission Grid during frequency conditions where ride-through is required.

(6) The Resource Entity or Interconnecting Entity (IE) of an IBR, Type 1 WGR or Type 2 WGR, shall ensure the Resource's frequency ride-through capability is set to the maximum level the equipment allows to meet or exceed the requirements of paragraphs (1) through (5) above as soon as practicable but no later than December 31, 2025 or at the time of its synchronization with the ERCOT Transmission Grid for new IBRs synchronizing after December 31, 2025. The Resource Entity must inform ERCOT (in a manner prescribed by ERCOT) of the date on which the IBR, Type 1 WGR or Type 2 WGR has fully maximized its ride-through capability to equipment limits. To establish ride-through capabilities to the maximum extent the equipment allows as used throughout Section 2.6.2, Frequency Ride-Through Requirements for Generation Resources and Energy Storage Resources, means making software, settings, firmware, and parameterization changes, which includes any memory upgrades to accommodate such changes that do not involve modifying other Resource equipment or components, to maximize the frequency ride-through capabilities of the Resource in accordance with Good Utility Practice.

(7) If an IBR, Type 1 WGR or Type 2 WGR with a Standard Generation Interconnection Agreement (SGIA) executed prior to August 1, 2024 cannot comply with paragraphs (1) through (6) above by December 31, 2025, the Resource Entity or IE shall, by April 1, 2025, submit an Initial Frequency Ride-Through Capability Report ("IFRTCR") pursuant to Section 2.11.1, Initial Frequency Ride-Through Capability Documentation and Reporting Requirements, and submit an extension request or notice of intent to request an exemption pursuant to Section 2.12.1, Exemptions and Extensions Process. The Resource must comply with the frequency ride-through requirements in effect on May 1, 2024 until the Resource maximizes its frequency ride-through capability as set forth in paragraph (6) above.

(8) If an IBR, Type 1 WGR or Type 2 WGR fails to perform in accordance with the applicable frequency ride-through requirements, the Resource Entity shall take the actions described in Section 2.13, Actions Following a Transmission-Connected Inverter-Based Resource (IBR), Type 1 Wind-powered Generation Resource (WGR) or Type 2 WGR Apparent Failure to Ride-Through.

2.6.2.1.1 Temporary Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs

(1) This Section applies to IBRs, Type 1 WGRs and Type 2 WGRs with an SGIA executed prior to August 1, 2024 that have not implemented modifications to satisfy paragraphs (1) through (5) of Section 2.6.2.1, Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs.

(2) Such Resources shall ride through the frequency conditions at the POIB specified in the following table:

Frequency Range	Delay to Trip
61.8 Hz or above	No time delay required
Below 61.8 Hz down to and including 61.6 Hz	Not less than 30 seconds
Below 61.6 Hz down to and including 60.6 Hz	Not less than 9 minutes
Above 59.4 Hz up to 60.6 Hz	No automatic tripping (continuous operation)
Above 58.4 Hz up to and including 59.4 Hz	Not less than 9 minutes
Above 58.0 Hz up to and including 58.4 Hz	Not less than 30 seconds
Above 57.5 Hz up to and including 58.0 Hz	Not less than 2 seconds
57.5 Hz or below	No time delay required

(3) This Section shall not affect the Resource Entity's responsibility to protect equipment from damaging operating conditions. The Resource Entity for an IBR, Type 1 WGR or Type 2 WGR subject to paragraph (2) above that is unable to remain reliably connected to the ERCOT Transmission Grid as set forth in paragraph (2), shall provide to ERCOT the information required in Section 2.11, Ride-Through Reporting Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs.

2.6.2.2 Frequency Ride-Through Requirements for Distribution Generation Resources

(DGRs) and Distribution Energy Storage Resources (DESRs)

(1) For any short-circuit fault or open-phase condition that occurs on the circuit to which the DGR or DESR is connected, the DGR or DESR will cease to energize and trip offline, and this will take priority over the frequency ride-through function.

(2) DGRs and DESRs must have over-/under-frequency relays set to ride through frequency conditions as specified in the following table:

Frequency (Hz)	Ride-Through Mode	Minimum Ride-through Time (seconds)
f > 61.8	No ride-through requirements	
61.2 < f ≤ 61.8	Mandatory Operation	299
58.8 ≤ f ≤ 61.2	Continuous Operation	continuous
57.0 ≤ f < 58.8	Mandatory Operation	299
f < 57.0	No ride-through requirements	

(3) Any Resource Entity with a DGR or DESR utilizing inverter-based generation that achieved Initial Synchronization before April 1, 2020 that is not capable of complying with the requirements of paragraph (2) above may request an exemption from those requirements. Such a request shall be submitted by November 2, 2020 and shall include documentation that demonstrates the DGR's or DESR's frequency ride-through capability to ERCOT's satisfaction. If, after reviewing the request and documentation, ERCOT determines the DGR or DESR is not capable of complying with the requirements of paragraph (2), then the DGR or DESR shall be exempt from those requirements, but shall be required to comply with those requirements to the greatest degree possible within its capability, as determined in writing by ERCOT. Upon replacement or retirement of the inverter, the DGR or DESR shall no longer be exempt and shall at that time be required to comply with the requirements of paragraph (2) or other applicable requirement.

(4) Section 2.12, Procedures for Frequency and Voltage Ride-Through Exemptions and Extensions for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, does not apply to exemptions to frequency ride-through requirements for DGRs and DESRs.

2.6.3 Frequency Ride-Through Requirements for Direct Current Ties (DC Ties)

(1) The following Direct Current Ties (DC Ties) are subject to the frequency ride-through requirements specified in this Section:

(a) Any DC Tie with an initial energization date after January 1, 2021.

(b) Any DC Tie that is modified by increasing the physical capacity of the DC Tie by 20 MW or more or by changing the power converter associated with the DC Tie, unless the replacement is in-kind.

(2) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure the DC Tie rides through the frequency conditions specified in the following table:

Frequency (Hz)	Minimum Ride-Through Time (seconds)
$f > 61.8$	No ride-through requirements
$61.2 < f \leq 61.8$	299
$58.8 \leq f \leq 61.2$	continuous
$57.0 \leq f < 58.8$	299
$f < 57.0$	No ride-through requirements

(3) Nothing in paragraph (2) above shall be interpreted to require a DC Tie to trip for frequency conditions beyond those for which ride-through is required.

(4) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure any protective over- or under-frequency relay for the DC Tie is set to enable the DC Tie to ride through any frequency condition beyond those defined in paragraph (2) above to the maximum extent possible within the DC Tie's capability.

2.7 System Voltage Profile and Operational Voltage Control

2.7.1 Introduction

(1) The system Voltage Profile is the set of normally desired Voltage Set Points for those Generation Resources and Energy Storage Resources (ESRs) required to provide Voltage Support Service (VSS).

(2) ERCOT coordinates and conducts studies with the Transmission Service Providers (TSPs) to determine and establish the Voltage Profile.

(3) ERCOT and/or the Transmission Operators (TOs) adjust Voltage Set Points to maintain system voltages within established limits.

2.7.2 Maintaining Voltage Profile

(1) ERCOT has the responsibility for monitoring and controlling the Voltage Profile and should use the following:

(a) Operations Engineering

(i) All voltage limits must be based on sound engineering studies that use the appropriate Network Operations Model. TSP study results should be made available to ERCOT; and

(ii) Transfer limits shall reflect voltage and/or reactive restrictions.

(b) Coordination

(i) Entities must coordinate high voltage limits in order to guarantee that the maximum continuous over-voltage of equipment is not exceeded. TOs shall notify ERCOT of normal operating voltage limits and post-contingency voltage limits for each bus;

(ii) Low voltage limits must be coordinated in order to prevent one Entity from being a burden to another;

(iii) Voltage limits shall not be violated during all normal and Credible Single Contingency conditions; and

(iv) The operation of all Reactive Power devices under the control of a TO or a Qualified Scheduling Entity (QSE) will be coordinated under the direction of ERCOT to maintain transmission voltage levels within normal limits and post-contingency voltages within post contingency limits. Static reactive devices will be managed to ensure that adequate dynamic reactive reserves are maintained at all times.

[NOGRR234: Replace item (iv) above with the following upon system implementation of NPRR1098:]

(iv) The operation of all Reactive Power devices under the control of a TO, Direct Current Tie Operator (DCTO), or a Qualified Scheduling Entity (QSE) will be coordinated under the direction of ERCOT to maintain transmission voltage levels within normal limits and post-contingency voltages within post contingency limits. Static reactive devices will be managed to ensure that adequate dynamic reactive reserves are maintained at all times.

(c) Notification

(i) Generation Resources or ESRs with voltage problems shall notify the TO to whom they are directly connected. TOs shall notify other affected TOs and ERCOT; and

(ii) ERCOT will monitor events and may direct actions to solve the problem.

(d) Response

(i) When the voltage levels deviate from established limits, ERCOT or the TO shall take immediate steps to relieve the condition using all available reactive resources.

(e) Monitoring

(i) TOs shall provide telemetry to ERCOT on all major transmission bus voltages.

(f) Controls

(i) ERCOT must be aware of the location of and availability of reactive capability;

(ii) ERCOT shall maintain displays to monitor Voltage Profiles and reactive flows; and

(iii) Controls to maintain Voltage Profiles may include but are not limited to capacitor switching, reactor switching, auto-transformer tap changing, Generation Resource and ESR reactive dispatch, transmission line switching, and Load shedding.

[NOGRR234: Replace item (f) above upon system implementation of NPRR1098:]

(f) Controls

(i) ERCOT must be aware of the location of and availability of reactive capability;

(ii) ERCOT shall maintain displays to monitor Voltage Profiles and reactive flows; and

(iii) Controls to maintain Voltage Profiles may include but are not limited to capacitor switching; reactor switching; auto-transformer tap changing; Generation Resource, ESR, and Direct Current Tie (DC Tie) reactive dispatch; transmission line switching; and Load shedding.

(g) Documentation

(i) Each TO must maintain a voltage/reactive plan for normal and Emergency Conditions and will provide this plan to adjacent TOs as well as ERCOT upon request.

(h) Emergency or Abnormal Conditions

(i) Transmission systems shall be designed so that effective reactive reserves shall be available without de-energizing other Facilities or shedding Load under normal conditions;

(ii) Major transmission lines shall be kept in service during light Load as much as possible. Lines should only be removed after all applicable reactive controls are implemented and studies show that reliability will not be degraded; and

(iii) Voltage reduction should not be done on the transmission system unless coordinated with adjacent TOs.

2.7.3 Real-Time Operational Voltage Control

2.7.3.1 Operational Guidelines

(1) The following guidelines describe ideal system operational characteristics and do not establish requirements for any particular Entity:

(a) General operational voltage limits are:

Nominal Voltage	Normal Operating Limits	Emergency Operating Limits
345	327.75 – 362.25	310.5 – 379.5
230	218.5 – 241.5	207 – 253
138	131.1 – 144.9	124.2 – 151.8
115	109.25 – 120.75	103.5 – 126.5
69	65.55 – 72.45	62.1 – 75.9

(b) Except for Transmission Facilities that are designed to operate outside of normal operating limits, transmission voltage should not exceed 105% nor fall below 95% of the nominal voltage during normal operation of the system.

(c) Transmission voltage during emergencies (including contingency events) should not exceed equipment over-excitation ratings.

(d) Transmission voltage during emergencies (including contingency events) should not result in customer voltage exceeding or falling below prescribed limits at distribution substations on the transmission system.

(e) Transmission voltage post contingency should not exceed 110% nor fall below 90% of the per-unit voltage, unless more restrictive limits have been specified by the TSP for their system, then those limits shall not be exceeded.

(f) Transmission voltage post contingency should not fall below any Under-Voltage Load Shedding (UVLS) set point during normal operations.

(g) The accuracy of any transmission voltage that appears to exceed normal or emergency limits should be verified prior to taking further actions.

(h) Major transmission lines should be kept in service during light Load as much as possible. Lines should only be removed after all applicable reactive controls are implemented and the practicality of additional generation Dispatch has been considered. Time permitting, studies should be conducted to verify that reliability will not be degraded by removing any major transmission line from service.

(i) Generally speaking, static reactive devices should be brought On-Line before predicted daily maximum Load or before dynamic reactive Resources reach operating limits. Static reactive devices will be taken Off-Line during daily Load decline and before dynamic reactive Resources reach operating limits.

2.7.3.2 ERCOT Responsibilities

(1) ERCOT shall be responsible for ordering necessary Generation Resources or ESRs On-Line to regulate transmission voltage and reactive flow.

(2) When voltage levels deviate from normal operating limits in the pre-contingency (base case) condition or from emergency operating limits in the post-contingency condition, ERCOT shall take immediate steps to restore voltage levels within the applicable operating limits using all available reactive resources. ERCOT may allow additional time for a TO to correct the voltage levels to within limits on sub-100kV facilities prior to ERCOT taking further steps to restore voltage levels. The steps ERCOT may take include, but are not limited to:

(a) Evaluating TO actions taken to correct voltage levels;

(b) Directing additional Generation Resources or ESRs On-Line;

(c) Re-dispatching Generation Resources or ESRs;

(d) Deploying additional Resources;

(e) Directing static Reactive Power resources to be put in service;

(f) Utilizing temporary changes to limits of Resources or Transmission Facilities;

(g) Developing a Constraint Management Plan (CMP);

(h) Adjusting a Voltage Set Point; and

(i) Shedding firm Load.

(3) ERCOT shall issue a VSS Dispatch Instruction to the designated QSE for adjustments that would require a Generation Resource or ESR to operate outside its Unit Reactive Limit (URL).

(4) For multi-generator buses, ERCOT may not instruct any single Generation Resource or ESR to operate beyond its Corrected Unit Reactive Limit (CURL) or URL until all Generation Resources and/or ESRs On-Line and interconnected at the same transmission bus are operating at their respective CURLs or URLs.

(5) ERCOT shall coordinate Automatic Voltage Regulator (AVR), dynamic and static reactive device Outages to ensure adequate reactive reserves are maintained.

(6) ERCOT shall maintain a performance log of QSE acknowledgements of VSS Dispatch Instructions.

(7) ERCOT shall be aware of the location of and availability of reactive power resources, including AVRs and Power System Stabilizers (PSSs), and shall monitor their statuses.

(8) ERCOT shall maintain displays to monitor Voltage Profiles and reactive flows.

(9) ERCOT shall, for each Generation Resource and ESR providing VSS, telemeter the Real-Time desired Voltage Set Point and the TSP-designated Point of Interconnection Bus (POIB) kV measurement via Inter-Control Center Communications Protocol (ICCP) to the QSE representing that Generation Resource or ESR.

(10) ERCOT shall instruct the TO to make Voltage Set Point adjustments, as necessary, within the Generation Resource's or ESR's URL provided to ERCOT.

2.7.3.3 TO/TSP Responsibilities

(1) Each TO shall be responsible for directing Voltage Set Points for each Generation Resource and ESR required to provide VSS interconnected to its TSP's Facilities. Each TO will adjust the Voltage Set Point by communicating directly with the Resource Entity or QSE responsible for the operation of the Generation Resource or ESR. Normal communication is to request voltage or Reactive Power be raised or lowered at a specified bus by a stated number of kV or MVAr (e.g., +1 kV, +20 MVAr, or -1 kV, -20 MVAr).

(2) Each TO shall monitor system voltages and shall operate voltage control equipment, including, but not limited to, static Reactive Power resources such as capacitors, reactors and transformer tap changers to maintain system voltages within limits.

(3) Each TO shall operate static Reactive Power resources within its operating area as required by its criteria while maintaining dynamic reactive reserves, both leading and lagging, provided by Generation Resources and ESRs. Except as reasonably necessary to ensure reliability or operational efficiency, TOs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource.

(4) Each TO shall telemeter to ERCOT via ICCP the Real-Time desired Voltage Set Point and actual voltage at the POIB for each Generation Resource or ESR interconnected to its system required to provide VSS. Each TO shall modify the telemetered Voltage Set Point as soon as practicable in order to match any verbal Voltage Set Point instruction issued.

(5) Each TO shall know the status of static transmission Reactive Power resources in its operating area and shall provide such information to ERCOT.

(6) When voltage levels deviate from established limits, the affected TO shall take immediate steps to relieve the condition using available reactive resources under its control.

(7) Each TSP shall, as soon as practicable, notify ERCOT of any temporary transmission voltage limit changes and shall coordinate with ERCOT to update the Network Operations Model with any permanent or long-term changes to voltage limits that deviate from those identified in Section 2.7.3.1, Operational Guidelines.

[NOGRR177 and NOGRR234: Replace applicable portions of Section 2.7.3.3 above with the following upon system implementation of NPRR857 or NPRR1098, respectively:]

2.7.3.3 TO/TSP Responsibilities

(1) Each TO shall be responsible for directing Voltage Set Points for each Generation Resource and ESR required to provide VSS interconnected to its TSP's Facilities. Each TO will adjust the Voltage Set Point by communicating directly with the Resource Entity or QSE responsible for the operation of the Generation Resource or ESR. Normal communication is to request voltage or Reactive Power be raised or lowered at a specified bus by a stated number of kV or MVAr (e.g., +1 kV, +20 MVAr, or -1 kV, -20 MVAr).

(2) Each TO shall monitor system voltages and shall operate voltage control equipment, including, but not limited to, static Reactive Power resources such as capacitors, reactors and transformer tap changers to maintain system voltages within limits.

(3) Each TO shall operate static Reactive Power resources within its operating area as required by its criteria while maintaining dynamic reactive reserves, both leading and lagging provided by Generation Resources and ESRs. Except as reasonably necessary to ensure reliability or operational efficiency, TOs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource or ESR.

(4) Each TO shall telemeter to ERCOT via ICCP the Real-Time desired Voltage Set Point and actual voltage at the POIB for each Generation Resource and ESR interconnected to its system required to provide VSS. Each TO shall modify the telemetered Voltage Set Point as soon as practicable in order to match any verbal Voltage Set Point instruction issued.

(5) Each TO shall know the status of static transmission Reactive Power resources in its operating area and shall provide such information to ERCOT.

(6) When voltage levels deviate from established limits, the affected TO shall take immediate steps to relieve the condition using available reactive resources under its control.

(7) Each TSP shall, as soon as practicable, notify ERCOT of any temporary transmission voltage limit changes and shall coordinate with ERCOT to update the Network Operations Model with any permanent or long-term changes to voltage limits that deviate from those identified in Section 2.7.3.1, Operational Guidelines.

(8) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Protocol Section 3.15.4, Direct Current Tie Owner and Direct Current Tie Operator (DCTO) Responsibilities Related to Voltage Support, shall be responsible for directing the operation of reactive power resources operated by that DCTO. Each TO shall telemeter to ERCOT via ICCP and to the DCTO via telemetry, the Real-Time desired target voltage at the DC Tie's Point of Interconnection Bus (POIB) and the actual voltage at the POIB. Each TO shall modify the telemetered target voltage to match any verbal target voltage instruction issued as soon as practicable.

(9) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Protocol Section 3.15.4 shall for each such DC Tie provide to ERCOT, via ICCP, the status of the DC Tie Facility's voltage control system. An "On" status will indicate that the control system is on and set to regulate the voltage at the DC Tie's POIB in automatic voltage control mode, and an "Off" status will indicate that the control system is off or in manual mode.

(10) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Protocol Section 3.15.4 shall, as soon as practicable, notify ERCOT when a DC Tie Facility experiences a change that affects its reactive capability, including any change to the operation mode of the DC Tie Facility's voltage control system or any temporary transmission voltage limit changes.

2.7.3.4 QSE Responsibilities

(1) Each QSE shall ensure that any Generation Resource or ESR that it represents and that is required to provide VSS responds to any VSS Dispatch Instruction including VSS Dispatch Instruction to exceed its CURL or URL or TO Voltage Set Point instruction within the time requirements specified in paragraph (3)(b) of Section 2.2.10, Generation Resource and Energy Storage Resource Response Time Requirements, even if the new Voltage Set Point is within the tolerance band identified in paragraph (4) of Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements. If the Resource Entity notifies the QSE that a Generation Resource or an ESR cannot comply with the VSS Dispatch Instruction or TO Voltage Set Point instruction, either the Resource Entity or its QSE shall, as soon as practicable, notify the Entity that issued the instruction. The Resource Entity or its QSE shall provide the reason for not being able to comply and an estimated time for resolution, when known.

(2) Each QSE representing a Generation Resource or ESR shall provide in Real-Time the desired Voltage Set Point and the associated POIB kV measurement to the Generation Resource or ESR.

(3) Each QSE will continuously monitor the status of its Resources' AVRs and PSSs.

(4) Each QSE must, as soon as practicable, notify ERCOT, via telemetry and verbal notifications, when a Generation Resource or ESR experiences a change that affects its reactive capability, including any change to the operation mode of the Generation Resource's or ESR's AVR. For each Generation Resource that is On-Line but not producing real power and is not capable of providing Reactive Power, each QSE must still telemeter its AVR status to ERCOT, but is not required to provide verbal notifications of its AVR status changes to ERCOT during these operating conditions.

2.7.3.5 Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements

(1) Each Resource Entity shall ensure that its Generation Resource(s) and ESR(s) responds to all VSS Dispatch Instruction or a TO Voltage Set Point instruction from its QSE or interconnecting TO within the time requirements specified in paragraph (3)(b) of Section 2.2.10, Generation Resource and Energy Storage Resource Response Time Requirements, even if the new Voltage Set Point is within the tolerance band identified in paragraph (4) below.

(2) Generation Resources or ESRs with high reactive loading resulting from abnormal conditions shall not reduce their reactive loading without the consent of ERCOT unless equipment damage is imminent based on the sole and reasonable judgment of the Resource Entity. In that case the Resource Entity will notify its QSE and its TO as soon as practicable of its action.

(3) Each Resource Entity shall monitor Real-Time provided Voltage Set Point instructions it receives. The Resource Entity shall inform its QSE and either the Resource Entity or its QSE shall notify the Resource Entity's TO, as soon as practicable, but not longer than 15 minutes from receipt of the instruction by the Resource Entity, if it cannot comply with TO Voltage Set Point instructions, or not longer than 30 minutes from being outside of the tolerance band if it cannot maintain the POIB voltage within the tolerance band identified in paragraph (4) below. If a Resource Entity cannot comply with a VSS Dispatch Instruction, the Resource Entity shall inform its QSE and its QSE shall notify ERCOT as soon as practicable but not longer than 15 minutes from the receipt of the instruction by the Resource Entity.

(4) A Resource Entity required to provide VSS shall maintain the Resource's voltage or Reactive Power schedule to maintain voltage at the POIB to be within a tolerance band of the Voltage Set Point while operating at less than or equal to the maximum reactive capability of the Generation Resource or ESR. A Generation Resource's or ESR's POIB voltage may be out of the tolerance band if it has exhausted all of its reactive capability. The tolerance bands are as follows:

Nominal Voltage	Tolerance Band kV
345	+/- 4kV

230	+/- 3kV
138	+/- 2kV
115	+/- 2kV
69	+/- 1kV

(5) Required reactive capability must be maintained at all times that the Generation Resource or ESR is On-Line. When a Generation Resource or ESR experiences a change that affects its reactive capability, the associated Resource Entity shall notify its QSE and TO, as soon as practicable but not longer than 30 minutes from becoming aware of the change in reactive capability.

(6) Each Resource Entity shall communicate any Resource Entity-owned transmission voltage limits that deviate from those identified in Section 2.7.3.1, Operational Guidelines, to ERCOT and to its QSE.

[NOGRR234: Insert Section 2.7.3.6 below upon system implementation of NPRR1098:]

2.7.3.6 DCTO Responsibilities and DC Tie Requirements

(1) Each DCTO operating a DC Tie subject to Protocol Section 3.15.4, Direct Current Tie Owner and Direct Current Tie Operator Responsibilities Related to Voltage Support, shall comply with any instruction from its designated TO with respect to the DC Tie's Reactive Power capability, including any instruction to maintain a specific voltage at the POIB, subject to the DC Tie's operating characteristic limits and voltage limits, and within the tolerances identified in paragraph (2) below, and subject to any superseding Dispatch Instruction from ERCOT.

(2) A DCTO operating a DC Tie subject to Protocol Section 3.15.4 shall maintain the voltage at the POIB within the tolerance band below while operating at less than or equal to the maximum reactive capability of the DC Tie. A DC Tie's POIB voltage may be out of the tolerance band if all of its reactive capability has been exhausted. The tolerance bands are as follows:

Nominal Voltage	Tolerance Band kV
345	+/- 4kV
230	+/- 3kV
138	+/- 2kV
115	+/- 2kV
69	+/- 1kV

(3) Required reactive capability must be maintained at all times that the DC Tie is not experiencing an Outage. When a DC Tie experiences a change that affects its reactive capability, the associated DCTO shall notify its TO as soon as practicable, but not longer than 30 minutes, from becoming aware of the change in reactive capability.

(4) Each DCTO shall, as soon as practicable, notify its TO of any temporary transmission voltage limit changes. The DC Tie owner shall coordinate with its DCTO on necessary changes to the Network Operations Model. The DCTO will coordinate with ERCOT to update the Network Operations Model with any permanent or long-term changes to voltage limits that deviate from those identified in Section 2.7.3.1, Operational Guidelines.

(5) Each DCTO shall provide to its TO, via telemetry, the status of the voltage control system for any DC Tie meeting the applicability requirements of paragraph (1) of Protocol Section 3.15.4. An "On" status will indicate that the control system is on and set to regulate the voltage at the DC Tie's POIB in automatic voltage control mode, and an "Off" status will indicate that the control system is off or in manual mode.

2.7.4 Special Consideration for Nuclear Power Plants

(1) In all planning studies and Real-Time operations, ERCOT and TOs shall maintain the switchyard voltage at each nuclear power plant at a value that does not violate its licensing basis with the Nuclear Regulatory Commission (NRC) ERCOT shall notify the QSE representing a nuclear power plant of the result of any studies where the voltage at the plant switchyard cannot be adequately maintained. ERCOT and the TO shall monitor the voltage in Real-Time. ERCOT shall provide notice to the QSE representing the nuclear power plant of any voltage inadequacy at the plant switchyard that cannot be corrected within 30 minutes. High and low limits on switchyard voltage at each nuclear power plant necessary to meet these requirements shall be specified in ERCOT Procedures.

2.7.5 Parameters for Standard Reactor and Capacitor Switching Plan

(1) TOs shall provide switching plans for automatically controlled reactors, capacitors, and other reactive controlled sources to ERCOT. For manually switched reactive devices, the TO shall provide its guidelines for the operation of these devices. These plans and guidelines shall be posted on the Market Information System (MIS) Secure Area and must be provided in accordance with the NOMCR or other ERCOT prescribed process. The parameters to be provided in the standard reactor and capacitor switching plan as required by Protocol Section 3.10.7.1.5, Reactors, Capacitors, and other Reactive Controlled Sources, are as follows:

Device Attributes

(a) Transmission Element name per Protocol Section 3.10.7.1, Modeling of Transmission Elements and Parameters;

(b) Substation name; and

(c) Schedules of device:

(i) Time-based;

(ii) Voltage-based;

(iii) Load-based;

(iv) Contingency-based;

(v) Normal Operation;

(vi) Emergency Operation;

(vii) Seasonal; and

(viii) Others as required by technology.

2.7.6 Unit Dispatch Beyond the Corrected Unit Reactive Limit or Unit Reactive Limit

(1) Each Generation Resource and ESR shall respond to ERCOT-instructed voltage control, including exceeding its CURL or URL. For multi-generator buses, ERCOT shall not instruct any single Generation Resource or ESR to operate beyond its CURL or URL until all Generation Resources and ESRs On-Line and interconnected at the same transmission bus, have been instructed to their respective CURLs or URLs.

2.8 Operation of Direct Current Ties

(1) ERCOT will confirm interconnected non-ERCOT balancing authority schedule profiles with the Direct Current Tie (DC Tie) operator, who will control the tie to the schedules agreed to by both the designated security coordinator for the interconnected non-ERCOT balancing authority and ERCOT.

(2) Any changes in the DC Tie schedules due to a de-rating of the DC Tie or transmission/generation capabilities in the non-ERCOT balancing authority will be communicated to ERCOT by the DC Tie Operator or designated security coordinator for the interconnected non-ERCOT balancing authority.

(3) ERCOT will coordinate operation of the DC Tie(s) with the DC Tie operator such that the Inadvertent Energy Account as defined in Protocol Section 6.5.4, Inadvertent Energy Account, is maintained as close to zero as practicable.

[NOGRR177: Replace Section 2.8 above with the following upon system implementation of NPRR857:]

2.8 Operation of Direct Current Ties

(1) ERCOT will confirm interconnected non-ERCOT balancing authority schedule profiles with the Direct Current Tie Operator (DCTO), who will control the tie to the schedules

agreed to by both the designated security coordinator for the interconnected non-ERCOT balancing authority and ERCOT.

(2) Any changes in the DC Tie schedules due to a de-rating of the DC Tie or transmission/generation capabilities in the non-ERCOT balancing authority will be communicated to ERCOT by the DCTO or designated security coordinator for the interconnected non-ERCOT balancing authority.

(3) ERCOT will coordinate operation of the Direct Current Tie(s) (DC Tie(s)) with the DCTO such that the Inadvertent Energy Account as defined in Protocol Section 6.5.4, Inadvertent Energy Account, is maintained as close to zero as practicable.

2.8.1 Inadvertent Energy Management

(1) The only inadvertent energy will be between ERCOT and the Southwest Power Pool (SPP) and/or Comision Federal de Electricidad (CFE). ERCOT shall track any differences between the net of scheduled energy across each DC Tie and the actual metered value at that DC Tie in an Inadvertent Energy Account between ERCOT and each interconnected non-ERCOT balancing authority as per Protocol Section 6.5.4, Inadvertent Energy Account. All inadvertent energy is placed in an inadvertent payback account to be paid back in kind.

[NOGRR177: Replace Section 2.8.1 above with the following upon system implementation of NPRR857:]

2.8.1 Inadvertent Energy Management

(1) The only inadvertent energy will be between ERCOT and non-ERCOT Control Areas. ERCOT shall track any differences between the net of scheduled energy across each DC Tie and the actual metered value at that DC Tie in an Inadvertent Energy Account between ERCOT and each interconnected non-ERCOT balancing authority as per Protocol Section 6.5.4, Inadvertent Energy Account. All inadvertent energy is placed in an inadvertent payback account to be paid back in kind.

2.9 Voltage Ride-Through Requirements for Generation Resources and Energy Storage Resources

(1) Except for Generation Resources and Energy Storage Resources (ESRs) subject to Sections 2.9.1, Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs), Type 2 WGRs and Type 3 WGRs, or 2.9.2, Voltage Ride-Through Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources

(DESRs), each Generation Resource or ESR must remain reliably connected to the ERCOT Transmission Grid during the following:

(a) Generator or inverter terminal voltages are within 5% of the rated design voltage and volts per hertz are less than 105% of generator rated design voltage and frequency;

(b) Generator or inverter terminal voltage deviations exceed 5% but are within 10% of the rated design voltage and persist for less than ten seconds;

(c) Generator or inverter volts per hertz conditions are less than 116% of rated design voltage and frequency and last for less than 1.5 seconds; and

(d) A transmission system fault (three-phase, single-phase or phase-to-phase), but not a unit bus fault, is cleared by the protection scheme coordinated between the Resource Entity and the Transmission Service Provider (TSP) on any line connected to the Resource's Point of Interconnection (POI), provided such lines are not connected to induction generators described in paragraph (12) of Protocol Section 3.15, Voltage Support.

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

(3) During operating conditions listed in paragraph (1) above, each Generation Resource and ESR subject to paragraph (1) shall not, during and following a transient voltage disturbance, cease providing real or reactive current except to the extent needed to provide frequency support or aid in voltage recovery. Each ESR, if consuming active power from the ERCOT System when operating in the charging mode, shall reduce or cease power consumption as necessary to aid in voltage recovery during and following transient voltage disturbances.

(4) Synchronous Generation Resources required to provide Voltage Support Service (VSS) shall have and maintain the following capability:

(a) Over-excitation limiters shall be provided and coordinated with the thermal capability of the generator field winding and protective relays in order to permit short-term reactive capability that allows at least 80% of the unit design standard (ANSI C50.13-1989), as follows:

Time (seconds)	10	30	60	120
Field Voltage %	208	146	125	112

After allowing temporary field current overload, the limiter shall operate through the automatic AC voltage regulator to reduce field current to the continuous rating. Return to normal AC voltage regulation after current reduction shall be automatic. The over-excitation limiter shall be coordinated with the over-excitation protection so over-excitation protection operates only for failure of the voltage regulator/limiter.

(b) Under-excitation limiters shall be provided and coordinated with loss-of-field protection to eliminate unnecessary generating unit disconnection as a result of operator error or equipment malfunction.

(5) Generation Resources and ESRs shall have protective relaying necessary to protect equipment from abnormal conditions and be consistent with protective relaying criteria described in Section 6.2.6.3.4, Generator and Energy Storage Resource Protection and Relay Requirements.

(6) The voltage ride-through requirements, including Section 2.9.1, do not apply to faults at or behind the POI, when clearing the fault effectively disconnects the Generation Resource from the ERCOT System.

(7) A Generation Resource or ESR may be tripped Off-Line or curtailed after the fault clearing period if part of an approved Remedial Action Scheme (RAS).

(8) The Resource Entity of each Generation Resource or ESR shall provide to ERCOT technical documentation of voltage ride-through capability upon request.

2.9.1 Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs), Type 2 WGRs and Type 3 WGRs

(1) All Inverter-Based Resources (IBRs) and Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs interconnected to the ERCOT Transmission Grid shall comply with voltage ride-through requirements as follows:

(a) Section 2.9.1.1, Preferred Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), shall apply to:

(i) An IBR with a Standard Generation Interconnection Agreement (SGIA) executed on or after August 1, 2024; and

(ii) An IBR that implements any modification, as described in paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, for which upgrades or facilities under a Generator Interconnection or Modification (GIM) was initiated on or after August 1, 2024, unless the modification was fully implemented prior to January 1, 2028.

(b) Section 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, shall apply to IBRs not subject to Section 2.9.1.1, and Type 1 WGRs and Type 2 WGRs.

(2) An IBR with an SGIA executed on or after August 1, 2024 or that implements a modification, as described in paragraph (1)(c) of Planning Guide Section 5.2.1 for which a GIM was initiated on or after August 1, 2024, shall meet or exceed the capability and performance requirements in the following sections of Institute of Electrical and Electronics Engineers (IEEE) 2800-2022, Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems ("IEEE 2800-2022 standard"), including any intra-standard cross references or definitions, unless otherwise clarified, modified, or exempted in the Protocols, these Operating Guides, or the Planning Guide:

(a) Section 5, Reactive power-voltage control requirements within the continuous operation region;

(b) Section 7, Response to TS abnormal conditions; and

(c) Section 9, Protection.

(3) All IBR plant requirements and IBR unit requirements described in the IEEE 2800-2022 standard apply at the Point of Interconnection Bus (POIB) and the individual IBR unit terminal, as appropriate, unless otherwise clarified, modified, or exempted in the Protocols, these Operating Guides, or the Planning Guide.

(4) An IBR, Type 1 WGR or Type 2 WGR with an original SGIA executed before August 1, 2024, that implements modifications complying with Section 2.9.1.2 prior to January 1, 2028, is not required to meet or exceed the capability and performance requirements in sections 5, 7 and 9 of the IEEE 2800-2022 standard. Any IBR modifications implemented on or after January 1, 2028 do not qualify for this exception.

(5) If a Type 3 WGR with an original SGIA executed before August 1, 2024, cannot fully meet the requirements in Table 11 of the IEEE 2800-2022 standard and implements a modification as described in paragraph (1)(c) of Planning Guide Section 5.2.1, for which upgrades to equipment or facilities under a GIM are completed prior to January 1, 2028, the Resource Entity may submit a notice of intent to request an exemption from meeting the voltage ride-through requirements in Table 11 of the IEEE 2800-2022 standard pursuant to Section 2.12, Procedures for Frequency and Voltage Ride-Through Exemptions and Extensions for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs.

(6) If an IBR with an SGIA executed on or after August 1, 2024, cannot meet or exceed the capability and performance requirements in sections 5, 7 and 9 of the IEEE 2800-2022 standard by its synchronization date, the Resource Entity or Interconnecting Entity (IE) may request a temporary extension to meet those requirements by submitting an extension request pursuant to Section 2.12. Any temporary extensions shall be minimized and not extend beyond December 31, 2028 or 24 months after the Commercial Operations Date, whichever is earlier.

(7) Type 1 and Type 2 WGRs are not required to meet or exceed the capability and performance requirements in sections 5, 7 and 9 of the IEEE 2800-2022 standard but

must meet or exceed the capability and performance requirements in Section 2.9.1.2 unless an extension or exemption applies under this Section or Section 2.12.

(8) The Resource Entity or IE for each IBR shall maximize the performance of its protection systems, controls, and other plant equipment (within equipment limitations) to meet and, if possible, exceed the capability and performance set forth in sections 5, 7 and 9 of the IEEE 2800-2022 standard. If an IBR with an SGIA executed prior to August 1, 2024 cannot fully meet the requirements of sections 5, 7, and 9 of the IEEE 2800-2022 standard, the Resource Entity shall maximize the performance of its protection systems, controls, and other plant equipment (within equipment limitations) to achieve, as close as reasonably possible, the capability and performance set forth in sections 5, 7 and 9 of the IEEE 2800-2022 standard as soon as practicable but no later than December 31, 2025 or by its Commercial Operations Date, whichever is later. The Resource Entity must inform ERCOT (in a manner prescribed by ERCOT) of the date on which the IBR, Type 1 WGR, Type 2 WGR or Type 3 WGR has fully maximized its capability with respect to the specified IEEE 2800-2022 requirements. To establish capabilities to the maximum extent the equipment allows as used throughout this Section means the Resource Entity must make software, settings, firmware, and parameterization changes, which includes any memory upgrades to accommodate such changes that do not involve modifying other Resource equipment or components, to maximize capabilities of the Resource with respect to the specified IEEE 2800-2022 requirements in accordance with Good Utility Practice.

(9) The addition of co-located Load as a modification, as described in paragraph (1)(c) of Planning Guide Section 5.2.1, for which a GIM was initiated, shall not trigger a change in ride-through requirements so long as the IBR, Type 1 WGR or Type 2 WGR has an original SGIA executed prior to August 1, 2024 unless the converters, inverters, supplemental dynamic reactive devices, or any other equipment that alters frequency or voltage ride-through capability are materially modified or replaced to meet any reliability requirements because of the co-located Load, in which case the Resource Entity shall continue to be subject to Section 2.9.1.2.

2.9.1.1 Preferred Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs)

(1) All IBRs subject to this Section shall ride through the root-mean-square voltage conditions in Table A: Applicable to WGR IBRs, or Table B: Applicable to PhotoVoltaic Generation Resources (PVGRs) and ESR IBRs, below, as applicable, as measured at the IBR's POIB:

Table A: Applicable to WGR IBRs

Root-Mean-Square Voltage (p.u. of nominal)	Minimum Ride-Through Time (seconds)
V > 1.20	May ride-through or trip
1.10 < V ≤ 1.20	1.0

0.90 ≤ V ≤ 1.10	continuous
0.70 ≤ V < 0.90	3.0
0.50 ≤ V < 0.70	2.5
0.25 ≤ V < 0.50	1.2
0.005625 ≤ V < 0.25	(V+0.084375)/0.5625
V < 0.005625	0.16

Table B: Applicable to PhotoVoltaic Generation Resources (PVGRs) and ESR IBRs

Root-Mean-Square Voltage (p.u. of nominal)	Minimum Ride-Through Time (seconds)
V > 1.20	May ride-through or trip
1.10 < V ≤ 1.20	1.0
0.90 ≤ V ≤ 1.10	continuous
0.70 ≤ V < 0.90	6.0
0.50 ≤ V < 0.70	3.0
0.25 ≤ V < 0.50	1.2
0.095625 ≤ V < 0.25	(V+0.084375)/0.5625
V < 0.095625	0.32

The minimum ride-through time in Tables A and B for voltage below the continuous operating range is inclusive of any amount of time the POIB voltage is below the specified voltage range. In the event of multiple excursions, the minimum ride-through time in Tables A or B is a cumulative time over a ten-second time window. For voltage between 0.005625 p.u. and 0.25 p.u. in Table A above and 0.095625 p.u. and 0.25 p.u. in Table B above, the minimum ride-through time is defined by a straight-line mathematical function where the duration is 0.15 seconds at zero voltage and 1.75 seconds at 0.9 p.u. voltage.

(2) Nothing in paragraph (1) above shall be interpreted to require an IBR to trip for voltage conditions beyond those for which ride-through is required.

(3) If protection systems (including, but not limited to protection for over-/under-voltage, rate-of-change-of-frequency, anti-islanding, and phase angle jump) are installed and activated to trip the IBR, they shall enable the IBR to ride through voltage conditions beyond those defined in paragraph (1) above to the maximum level the equipment allows.

(4) An IBR shall inject electric current when required to ride-through voltage conditions. Except when caused by reductions associated with intermittent primary energy source availability (e.g., wind speed or solar irradiance), an IBR shall not reduce active current injection during voltage conditions requiring ride-through unless allowed in this paragraph or to provide appropriate frequency response. When the POIB voltage is outside the continuous operating voltage range, an IBR shall continue to deliver pre-disturbance active current unless reduction is needed to allow for voltage support or otherwise specified by ERCOT or the interconnecting TSP. Any necessary reductions in active current to prioritize reactive current shall be relative to the voltage change at the

POIB. Typically, more aggressive reductions in active current to allow for additional reactive current (if needed to stay within its current limitations) will occur at lower voltages (e.g., 0.4 p.u. or lower) but settings should be made based on the local needs of the ERCOT System where the IBR interconnects and ensures sufficient active current is available for protection system sensing. An IBR shall return to its pre-disturbance level of real power injection as soon as possible but no more than one second after POIB voltage recovers to normal operating range. ERCOT, in its reasonable discretion, may allow slower real power injection recovery rates if necessary for reliability as determined by the impacted TSP or ERCOT.

(5) IBR plant controls, turbine controls and/or inverter controls shall not disconnect the plant, or any individual inverter/turbine, or prevent current exchange between the IBR and the ERCOT Transmission Grid during voltage conditions where ride-through is required.

(6) If instantaneous over-current or over-voltage protection systems are installed and activated to trip the IBR, they shall use filtered quantities or time delays to prevent misoperation while providing the desired equipment protection. Any alternating current instantaneous over-voltage protection that could disrupt IBR power output shall use a measurement window of at least one cycle of fundamental frequency.

(7) An IBR shall not use phase angle jump or rate-of-change-of-frequency measurement quantities as a basis for reducing power output or tripping offline during fault conditions and subsequent recovery to a steady-state operating point within the ride-through profiles specified in paragraph (1) above.

(8) The Resource Entity or IE for each IBR shall maximize the performance of its protection systems, controls, and other plant equipment (within equipment limitations) to meet and, if possible, exceed the requirements of paragraphs (1) through (7) above by December 31, 2025. A Resource Entity or IE may request an extension for upgrades or retrofits to confirm capability specified in paragraph (7) above by following the extension process set forth in Section 2.12, Procedures for Frequency and Voltage Ride-Through Exemptions and Extensions for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs. Any temporary extensions under this paragraph shall be minimized and not extend beyond December 31, 2028.

(9) A Resource Entity of a Type 3 WGR may seek an extension for completing modifications to meet the voltage ride-through performance Table A in paragraph (1) above by following the extension process set forth in Section 2.12. During any extension, the Resource Entity shall ensure the WGR's voltage ride-through capability is set to the maximum level the equipment allows as soon as practicable.

(10) Any temporary extensions for IBRs with SGIAs on or after August 1, 2024 shall be minimized and not extend beyond December 31, 2028. Temporary extensions for performance that do not meet the voltage ride-through performance in Table A in paragraph (1) of Section 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, are not allowed.

(11) If an IBR fails to perform in accordance with the applicable voltage ride-through requirements, the Resource Entity for the IBR shall take the actions described in Section 2.13, Actions Following a Transmission-Connected Inverter-Based Resource (IBR), Type 1 Wind-powered Generation Resource (WGR) or Type 2 WGR Apparent Failure to Ride-Through.

2.9.1.2 Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs

(1) All IBRs, Type 1 WGRs and Type 2 WGRs subject to this Section in accordance with paragraph (1) of Section 2.9.1, Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs), Type 2 WGRs, and Type 3 WGRs, shall ride through the root-mean-square voltage conditions in Table A below as measured at the Resource's POIB:

Table A

Root-Mean-Square Voltage (p.u. of nominal)	Minimum Ride-Through Time (seconds)
V > 1.20	May ride-through or may trip
1.175 < V ≤ 1.2	0.2
1.15 < V ≤ 1.175	0.5
1.10 < V ≤ 1.15	1.0
0.90 ≤ V ≤ 1.10	continuous
0.0 < V < 0.90	(V+0.084375)/0.5625
V = 0.0	0.15

For voltage between zero and 0.9 p.u. the minimum ride-through time in Table A above is defined by a straight line mathematical function where the duration is 0.15 seconds at zero voltage and 1.75 seconds at 0.9 p.u. voltage.

(2) Nothing in paragraph (1) above shall be interpreted to require an IBR, Type 1 WGR or Type 2 WGR to trip for voltage conditions beyond those for which ride-through is required.

(3) If protection systems (including, but not limited to protection for over-/under-voltage, rate-of-change-of-frequency, anti-islanding, and phase angle jump) are installed and activated to trip the IBR, Type 1 WGR or Type 2 WGR, they shall enable the IBR, Type 1 WGR or Type 2 WGR to ride through voltage conditions beyond those defined in paragraph (1) above to the maximum level the equipment allows.

(4) An IBR, Type 1 WGR or Type 2 WGR shall inject electric current when required to ride-through voltage conditions. Except when caused by reductions associated with intermittent primary energy source availability (e.g., wind speed or solar irradiance), an IBR, Type 1 WGR or Type 2 WGR shall not reduce active current injection during voltage conditions requiring ride-through unless allowed in this paragraph or to provide

appropriate frequency response. When the POIB voltage is outside the continuous operating voltage range, an IBR shall continue to deliver pre-disturbance active current unless reduction is needed for voltage support or otherwise specified by ERCOT or the interconnecting TSP. Any necessary reductions in active current to prioritize reactive current shall be relative to the voltage change at the POIB. Typically, more aggressive reductions in active current to allow for additional reactive current (if needed to stay within its current limitations) will occur at lower voltages (e.g., 0.4 p.u. or lower) but settings shall be based on the local needs of the area of the ERCOT System to which the IBR interconnects and ensure sufficient active current is available for protection system sensing. An IBR, Type 1 WGR or Type 2 WGR shall return to its pre-disturbance level of real power injection as soon as possible but no more than one second after POIB voltage recovers to normal operating range. Slower real power injection recovery rates may be allowed if necessary for reliability as documented by the impacted TSP or ERCOT.

(5) IBR, Type 1 WGR and Type 2 WGR plant controls, turbine controls, and/or inverter controls shall not disconnect the plant or any individual inverter/turbine, or prevent current exchange between the Resource and the ERCOT Transmission Grid during voltage conditions where ride-through is required.

(6) If instantaneous over-current or over-voltage protection systems are installed and activated to trip the IBR, Type 1 WGR or Type 2 WGR, they shall use filtered quantities or sufficient time delays to prevent misoperation while providing the desired equipment protection. Any alternating current instantaneous over-voltage protection that could disrupt power output shall use a measurement period of at least one cycle (of fundamental frequency).

(7) An IBR, Type 1 WGR or Type 2 WGR shall not use phase angle jump or rate-of-change-of-frequency measurement quantities as a basis for reducing power output or tripping offline during fault conditions and subsequent recovery to a steady-state operating point within the ride-through profiles specified in paragraph (1) above.

(8) The Resource Entity for each IBR, Type 1 WGR or Type 2 WGR shall maximize the performance of its protection systems, controls, and other plant equipment (within equipment limitations) to meet and, if possible, exceed the performance requirements in paragraphs (1) through (7) above as soon as practicable but no later than December 31, 2025 or by its Commercial Operations Date, whichever is later.

(9) If an IBR, Type 1 WGR or Type 2 WGR with an SGIA executed prior to August 1, 2024 cannot comply with paragraphs (1) through (7) above by December 31, 2025 after maximizing the performance of its protection systems, controls, and other plant equipment (within equipment limitations), the Resource Entity shall, by April 1, 2025, submit an Initial Voltage Ride-Through Capability Report ("IVRTCR") pursuant to Section 2.11.2, Initial Voltage Ride-Through Capability Documentation and Reporting Requirements, and request an extension to comply pursuant to Section 2.12, Procedures for Frequency and Voltage Ride-Through Exemptions and Extensions for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs. If the Resource Entity submits an IVRTCR and

cannot comply with paragraphs (1) through (7) above with an extension, it must submit a notice of intent to request an exemption pursuant to Section 2.12. The Resource Entity must comply with the voltage ride-through requirements in effect on May 1, 2024 until it maximizes its voltage ride-through capability.

(10) If an IBR, Type 1 WGR or Type 2 WGR fails to perform in accordance with the applicable voltage ride-through requirements, the Resource Entity shall take the actions described in Section 2.13, Actions Following a Transmission-Connected Inverter-Based Resource (IBR), Type 1 Wind-powered Generation Resource (WGR) or Type 2 WGR Apparent Failure to Ride-Through.

2.9.2 Voltage Ride-Through Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs)

(1) For any short-circuit fault or open-phase condition that occurs on the distribution circuit to which the DGR or DESR is connected, the DGR or DESR will cease to energize and trip offline, and will take priority over the voltage ride-through function.

(2) DGRs utilizing synchronous generation must have over-/under-voltage relays set to ride through the following operating conditions:

Voltage (p.u. of nominal)	Minimum Ride-Through Time (seconds)
$0.88 \leq V \leq 1.10$	continuous
$0.70 \leq V < 0.88$	Linear slope of 4 s/1 p.u. voltage starting at 0.7 s @ 0.7 p.u.

(3) DGRs and DESRs utilizing inverter-based generation must be designed and relays must be set to ride through the following operating conditions:

Voltage (p.u. of nominal)	Ride-Through Mode	Minimum Ride-Through Time (seconds)
$1.10 < V \leq 1.20$	Momentary Cessation	12
$0.88 \leq V \leq 1.10$	Continuous Operation	continuous
$0.70 \leq V < 0.88$	Mandatory Operation	20
$0.50 \leq V < 0.70$	Mandatory Operation	10
$V < 0.50$	Momentary Cessation	1

(4) Any Resource Entity with a DGR or DESR utilizing inverter-based generation that achieved Initial Synchronization before August 1, 2020 that is not capable of complying with the requirements of paragraph (3) above may request an exemption from those requirements. Such a request shall be submitted by November 2, 2020 and shall include documentation that demonstrates the DGR's or DESR's voltage ride-through capability to ERCOT's satisfaction. If, after reviewing the request and documentation, ERCOT determines the DGR or DESR is not capable of complying with the requirements of paragraph (3), then the DGR or DESR shall be exempt from those requirements, but shall be required to comply with those requirements to the greatest degree possible within its

capability, as determined in writing by ERCOT. Upon replacement or retirement of the inverter, the DGR or DESR shall no longer be exempt and shall at that time be required to comply with the requirements of paragraph (3) or other applicable requirement.

2.10 Voltage Ride-Through Requirements for DC Ties

(1) The following Direct Current Ties (DC Ties) are subject to the voltage ride-through requirements specified in this Section:

(a) Any DC Tie with an initial energization date after January 1, 2021.

(b) Any DC Tie that is modified by increasing the physical capacity of the DC Tie by 20 MW or more or by changing the power converter associated with the DC Tie, unless the replacement is in-kind.

(2) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure the DC Tie rides through the root-mean-square voltage conditions specified in Table A and the instantaneous phase voltage conditions specified in Table B, as measured at the DC Tie's Point of Interconnection Bus (POIB):

Table A

Root-Mean-Square Voltage (p.u. of nominal)	Minimum Ride-Through Time (seconds)
V > 1.20	No ride-through requirements
1.10 < V ≤ 1.20	1.0
0.90 ≤ V ≤ 1.10	continuous
0.70 ≤ V < 0.90	6.0
0.50 ≤ V < 0.70	3.0
0.25 ≤ V < 0.50	1.2
V < 0.25	0.16

Table B

Instantaneous Phase Voltage (p.u. of nominal)	Minimum Ride-Through Time (milliseconds)
V > 1.80	No ride-through requirements
1.70 < V ≤ 1.80	0.2
1.60 < V ≤ 1.70	1.0
1.40 < V ≤ 1.60	3.0
1.20 < V ≤ 1.40	15.0

(3) Nothing in paragraph (2) above shall be interpreted to require a DC Tie to trip for voltage conditions beyond those for which ride-through is required.

(4) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure any protective over- or under-voltage relay for the DC Tie is set to enable the DC Tie to ride through any voltage condition beyond those defined in paragraph (2) above to the maximum extent possible within the DC Tie's capability.

(5) A DC Tie shall not cease injecting electric current during any period in which ride-through is required pursuant to paragraph (2) and paragraph (4) above. A DC Tie shall return to the pre-disturbance level of real power transfer within 1 second of POIB voltage recovery to normal operating range.

2.11 Ride-Through Reporting Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs

(1) If the Resource Entity for an Inverter-Based Resource (IBR), Type 1 Wind-powered Generation Resource (WGR) or Type 2 WGR believes one or more of its Resources (i) has already maximized its ride-through capabilities to meet or exceed the applicable ride-through performance requirements, or (ii) will maximize its ride-through capabilities with available software, firmware, settings and parameterization changes to meet or exceed the applicable ride-through performance requirements before December 31, 2025, the Resource Entity must submit to ERCOT accurate models reflecting the field settings of the IBR, Type 1 WGR or Type 2 WGR consistent with applicable requirements for model updates in these Protocols and Other Binding Documents.

(2) Until an IBR, Type 1 WGR or Type 2 WGR completes the work to maximize ride-through capability as required in Sections 2.6.2.1, Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, 2.9.1, Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs), Type 2 WGRs and Type 3 WGRs, 2.9.1.1, Preferred Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), and 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, the Resource must comply with the ride-through requirements in effect on May 1, 2024.

(3) Upon completing the work to maximize ride-through capability as required in Sections 2.6.2.1, 2.9.1, 2.9.1.1, and 2.9.1.2, the Resource Entity shall inform ERCOT (in a manner prescribed by ERCOT) it has completed the work to maximize ride-through capability for each Resource.

2.11.1 Initial Frequency Ride-Through Capability Documentation and Reporting Requirements

(1) The Resource Entity of an IBR, Type 1 WGR or Type 2 WGR with a Standard Generation Interconnection Agreement (SGIA) executed prior to August 1, 2024 that

cannot comply with paragraphs (1) through (6) of Section 2.6.2.1, Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, by December 31, 2025 shall, by April 1, 2025, submit to ERCOT via the Resource Integration and Ongoing Operations (RIOO) system, or as otherwise directed by ERCOT, an Initial Frequency Ride-Through Capability Report ("IFRTCR") containing the following:

(a) The Resource Entity Data Universal Numbering System (DUNS) Number;

(b) IBR/WGR Site Name;

(c) IBR/WGR Unit Name(s);

(d) Nodal Operating Guide Section(s) with which the Resource cannot comply;

(e) Current frequency ride-through capability in a format similar to the table in paragraph (1) of Section 2.6.2.1;

(f) Known frequency ride-through limitations of the IBR, Type 1 WGR or Type 2 WGR as compared to the requirements in paragraphs (1) through (5) of Section 2.6.2.1;

(g) A detailed description of the technical limitation preventing the Resource from meeting the ride-through requirement(s), including a letter signed by an officer or executive of the original equipment manufacturer (or subsequent support company if the original equipment manufacturer is no longer in business) or an engineering consulting firm verifying the limitations:

  (i) If a Resource Entity cannot address the entire plant design with a letter required in paragraph (1)(g) above, the Resource Entity must supplement a letter from the original equipment manufacturer for its equipment (or subsequent support company if the original equipment manufacturer is no longer in business) or an engineering consulting firm by providing a notarized attestation sworn to by the Resource Entity's highest-ranking representative, official, or officer with binding authority over the entity attesting to: the efforts made to obtain the letter, why those efforts failed, and which parts of the plant design is attested to. The attestation shall also include a detailed description of the technical limitation(s) preventing the Resource from meeting the ride-through requirement, including any information on technical limitations on all or part of the Resource which the Resource Entity is able to obtain from original equipment manufacturers or an engineering consulting firm under paragraph (1)(g) above;

(h) Available software, firmware, settings or parameterization modifications the Resource Entity will implement to maximize the frequency ride-through capability of the IBR, Type 1 WGR or Type 2 WGR within known equipment limitations, to the greatest extent possible;

(i) To the extent the Resource Entity chooses to implement changes to existing equipment other than software, firmware, settings or parameterization modifications that increase the frequency ride-through capability, identification of any such equipment modifications;

(j) Expected post-modification Resource capability in a format similar to the table in paragraph (1) of Section 2.6.2.1 and documentation of any expected remaining limitation(s) following implementation of such modifications;

(k) A schedule for implementing the modification(s);

(l) A model accurately representing expected performance reflecting all technical limitations, or a statement that there are no new models available other than what is currently submitted to ERCOT that already reflect all technical limitations in frequency ride-through capability; and

(m) A description of any limitation that cannot be accurately represented in a model.

(2) If a Resource Entity does not timely provide to ERCOT an IFRTCR by April 1, 2025, the Resource will not be eligible for an exemption or extension to comply with the ride-through requirements. If a Resource Entity timely provides an IFRTCR by April 1, 2025 and ERCOT requests additional information, it will not render the Resource ineligible for an exemption.

2.11.2 Initial Voltage Ride-Through Capability Documentation and Reporting Requirements

(1) The Resource Entity of an IBR, Type 1 WGR or Type 2 WGR with an SGIA executed prior to August 1, 2024, that cannot comply with paragraphs (1) through (7) of Section 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, by December 31, 2025 shall, by April 1, 2025, submit to ERCOT via the RIOO system, or as otherwise directed by ERCOT, an Initial Voltage Ride-Through Capability Report ("IVRTCR") containing the following:

(a) The Resource Entity DUNS Number;

(b) IBR/WGR Site Name;

(c) IBR/WGR Unit Name(s);

(d) Nodal Operating Guide Section(s) with which the Resource cannot comply;

(e) Current voltage ride-through capability in a format similar to the table in paragraph (1) of Section 2.9.1.2;

(f) Known voltage ride-through limitations of the IBR, Type 1 WGR or Type 2 WGR as compared to the requirements in paragraphs (1) through (7) of Section 2.9.1.2;

(g) A detailed description of the technical limitation preventing the Resource from meeting the ride-through requirement(s), including a letter signed by an officer or executive of the original equipment manufacturer (or subsequent support company if the original equipment manufacturer is no longer in business) or an engineering consulting firm verifying the limitations:

(i) If a Resource Entity cannot address the entire plant design with a letter required in paragraph (1)(g) above, the Resource Entity must supplement a letter from the original equipment manufacturer for its equipment (or subsequent support company if the original equipment manufacturer is no longer in business) and an engineering consulting firm by providing a notarized attestation sworn to by the Resource Entity's highest-ranking representative, official, or officer with binding authority over the entity attesting to: the efforts made to obtain the letter, why those efforts failed, and which parts of the plant design is attested to. The attestation shall also include a detailed description of the technical limitation(s) preventing the Resource from meeting the ride-through requirement, including any information on technical limitations on all or part of the Resource which the Resource Entity is able to obtain from original equipment manufacturers or an engineering consulting firm under paragraph (1)(g) above;

(h) Available software, firmware, settings, or parameterization modifications the Resource Entity will implement to maximize the voltage ride-through capability of the IBR, Type 1 WGR or Type 2 WGR to approach or meet the voltage ride-through requirements in paragraphs (1) through (7) of Section 2.9.1.2 within known equipment limitations, to the greatest extent possible;

(i) To the extent the Resource Entity chooses to implement changes to existing equipment other than software, firmware, settings or parameterization modifications that increase the voltage ride-through capability, identification of any such equipment modifications;

(j) Expected post-modification Resource capability in a format similar to the table in paragraph (1) of Section 2.9.1.2 and documentation of any expected remaining limitation(s) following implementation of such modifications;

(k) A schedule for implementing the modification(s);

(l) A model accurately representing expected performance reflecting all technical limitations, or a statement that there are no new models available other than what is currently submitted to ERCOT that already reflect all technical limitations in voltage ride-through capability; and

(m) A description of any limitation that cannot be accurately represented in a model.

(2) If a Resource Entity does not timely provide to ERCOT an IVRTCR by April 1, 2025, the Resource will not be eligible for an exemption or extension to comply with the ride-

through requirements. If a Resource Entity timely provides an IVRTCR by April 1, 2025 and ERCOT requests additional information, it will not render the Resource ineligible for an exemption.

2.12 Procedures for Frequency and Voltage Ride-Through Exemptions and Extensions for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs

2.12.1 Exemptions and Extensions Process

(1) If an Inverter-Based Resource (IBR), Type 1 Wind-powered Generation Resource (WGR) or Type 2 WGR has a technical limitation preventing it from fully meeting the frequency ride-through requirements in paragraphs (1) through (5) of Section 2.6.2.1, Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, or the voltage ride-through requirements in paragraphs (1) through (7) of Section 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, or as otherwise specified in paragraph (5) through (7) of Section 2.9.1, Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs), Type 2 WGRs and Type 3 WGRs, or certain voltage ride-through requirements in accordance with paragraph (9) of Section 2.9.1.1, Preferred Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), the Resource Entity or Interconnecting Entity (IE) ("Requesting Entity") must submit to ERCOT, by April 1, 2025: (i) a request for an extension to meet such requirements and/or (ii) a notice of intent to request an exemption based on standards established in a subsequent Nodal Operating Guide Revision Request (NOGRR).

(2) For any IBR, Type 1 WGR or Type 2 WGR with a Standard Generation Interconnection Agreement (SGIA) dated before August 1, 2024, a notice of intent to request an exemption must be submitted to ERCOT on or before April 1, 2025 as part of the Initial Frequency Ride-Through Capability Report ("IFRTCR") and Initial Voltage Ride-Through Capability Report ("IVRTCR") as applicable. No new notices of intent to request an exemption beyond April 1, 2025, detailing additional technical limitations of ride-through requirements are allowed. A Resource Entity may only request an exemption based upon the technical limitations identified in its April 1, 2025 IFRTCR and/or IVRTCR. An exemption request and the ability to provide supplemental information, including updated models reflecting improved ride-through capability, will be established under processes in a subsequent NOGRR.

(3) ERCOT, in its sole and reasonable discretion, will grant an extension if all of the following conditions exist:

(a) Circumstances beyond the Requesting Entity's reasonable control prevented it from meeting the deadline;

(b) The extension request demonstrates the Requesting Entity's good faith efforts to minimize the extension's duration;

(c) The Requesting Entity has provided accurate models that include all limitations and describes all limitations the Requesting Entity cannot model and represents to ERCOT the model is accurate;

(d) The date for the requested extension for a Resource with an SGIA before August 1, 2024 does not exceed December 31, 2027; and

(e) The date for the requested extension for a Resource with an SGIA after August 1, 2024 does not exceed December 31, 2028.

(4) For any IBR, Type 1 WGR or Type 2 WGR with an approved exemption or extension, the documented maximum capabilities will become the new performance requirements until the exemption or extension has ended.

(5) Exemptions and extensions take effect immediately upon approval by ERCOT and apply only to the extent approved by ERCOT.

(6) Exemptions continue until:

(a) The IBR, Type 1 WGR or Type 2 WGR fully implements a modification as described in paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, that is synchronized after January 1, 2028; or

(b) The IBR, Type 1 WGR or Type 2 WGR fully implements a modification that eliminates the need for the exemption.

(7) If ERCOT or the Resource Entity becomes aware of a newly available software, firmware, settings or parameterization modification for a Resource with an exemption, the Resource Entity shall: (i) submit an implementation plan to ERCOT for approval within 90 days, and (ii) if ERCOT approves the plan, implement the plan within 180 days, unless ERCOT approves a longer timeline.

(8) Extensions shall end in accordance with Section 2.12.1.2, Submission of Extension Requests.

(9) The deadlines in Section 2.12.1.2 may be modified by mutual written agreement of ERCOT and the Requesting Entity.

(10) Until the consideration of an exemption, extension, or appeal process is finalized, the IBR, Type 1 WGR or Type 2 WGR with an SGIA prior to August 1, 2024 that has submitted an extension request or notice of intent to request an exemption and any required documentation by April 1, 2025 must meet the greater of: (i) its documented maximum ride-through capability, or (ii) its performance requirements in effect on May 1, 2024 until there is a non-appealable Public Utility Commission of Texas (PUCT) final order.

(11) ERCOT shall not use a Resource Entity's IFRTCR, IVRTCR, or notice of intent to request an exemption as a basis for referral to the Reliability Monitor so long as the Resource meets the applicable ride-through requirements set forth in paragraph (10) above.

(12) All information submitted under Sections 2.11, Ride-Through Reporting Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, and 2.12, Procedures for Frequency and Voltage Ride-Through Exemptions and Extensions for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, shall be considered Protected Information.

2.12.1.1 Submission of Exemption Requests

(1) A Requesting Entity may seek an exemption for an IBR, Type 1 WGR or Type 2 WGR as follows:

(a) A Requesting Entity for an IBR, Type 1 WGR or Type 2 WGR with an SGIA executed prior to August 1, 2024 may seek exemptions from ride-through requirements in paragraphs (1) through (5) of Section 2.6.2.1, Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, or Section 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs.

(b) A Requesting Entity for a Type 3 WGR with an original SGIA executed prior to August 1, 2024, that meets the criteria in paragraph (5) of Section 2.9.1, Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs), Type 2 WGRs and Type 3 WGRs, may seek an exemption as described in that Section.

(2) The Resource Entity intending to request an exemption for an IBR, Type 1 WGR, Type 2 WGR must, by April 1, 2025, submit an IFRTCR or IVRTCR with a notice of intent to request an exemption describing the need for the exemption consistent with Sections 2.11.1, Initial Frequency Ride-Through Capability Documentation and Reporting Requirements, or 2.11.2, Initial Voltage Ride-Through Capability Documentation and Reporting Requirements.

2.12.1.2 Submission of Extension Requests

(1) Unless otherwise approved by ERCOT, extension requests must be submitted by April 1, 2025. A Requesting Entity may seek an extension for an IBR, Type 1 WGR or Type 2 WGR as follows:

(a) A Requesting Entity for an IBR, Type 1 WGR or Type 2 WGR with an SGIA executed prior to August 1, 2024, may seek extensions for ride-through requirements in paragraphs (1) through (5) of Section 2.6.2.1, Frequency Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, or Section 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs.

(b) A Requesting Entity for an IBR with an SGIA executed on or after August 1, 2024 may seek extensions as contemplated in paragraph (6) of Section 2.9.1, Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs), Type 2 WGRs and Type 3 WGRs, or paragraphs (9) or (10) of Section 2.9.1.1, Preferred Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs).

(2) A Requesting Entity, through its Authorized Representative, may initiate a request for an extension under this Section by submitting written notice of the request to ERCOT through the Resource Integration and Ongoing Operations (RIOO) system (or as otherwise specified by ERCOT), with the following information:

(a) Requesting Entity Name;

(b) Requesting Entity DUNS Number;

(c) IBR/WGR Site Name;

(d) IBR/WGR Unit Name(s);

(e) Nodal Operating Guide Section(s) under which the extension is requested;

(f) A detailed description of the grounds for the extension and the basis for each request;

(g) Documentation from the equipment manufacturer describing any known limitations associated with the extension request, a description of proposed modifications, and a schedule for implementing modifications; and

(h) Other information specified in this Section.

(3) The Requesting Entity for an IBR with an SGIA executed on or after August 1, 2024, seeking an extension contemplated in paragraph (6) of Section 2.9.1, or paragraph (10) of Section 2.9.1.1 shall, at a minimum, submit the following information to ERCOT:

(a) Documentation describing the justification for granting the extension;

(b) A model accurately representing all technical limitations and expected performance;

(c) A description of any limitation that cannot be accurately represented in a model;

(d) Data and information identified in paragraphs (5) through (7) below, as applicable; and

(e) Any other data or information ERCOT reasonably deems necessary to evaluate granting the extension.

(4) If a Requesting Entity submits a request for an extension to meet the performance requirements in sections 5, 7, and 9 of the Institute of Electrical and Electronics Engineers (IEEE) 2800-2022, Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems ("IEEE 2800-2022 standard") as described in paragraph (6) of Section 2.9.1, it must provide to ERCOT:

(a) Evidence from its original equipment manufacturer (or subsequent inverter/turbine vendor support company if the original equipment manufacturer is no longer in business) of technical infeasibility to comply with any of the performance requirements in sections 5, 7, and 9 of the IEEE 2800-2022 standard by its synchronization date;

(b) A description of proposed modifications; and

(c) The schedule for implementing those modifications. Any temporary extension shall be minimized and not extend beyond December 31, 2028 or 24 months after the Resource's Commercial Operations Date, whichever is earlier.

(5) If a Requesting Entity submits a request for an extension to meeting the performance requirements in Table A in paragraph (1) as contemplated in paragraph (10) of Section 2.9.1.1, it must provide to ERCOT:

(a) Documented evidence from its equipment manufacturer of technical infeasibility to comply with the performance requirements in paragraph (1) of Section 2.9.1.1 by the IBR's/WGR's synchronization date;

(b) A description of proposed modifications; and

(c) The schedule for implementing those modifications. Any extensions under this paragraph shall be minimized and not extend beyond December 31, 2028. ERCOT will not grant any temporary extensions for performance that do not meet the voltage ride-through performance requirements in Table A in paragraph (1) of Section 2.9.1.2.

(6) Extensions will terminate according to their terms at the time granted or at another date approved by ERCOT in writing.

2.12.1.3 Timeline for Submission and Determination of Extension Requests

(1) As soon as practicable after receiving a request for an extension, ERCOT shall provide the Requesting Entity with written confirmation of receipt and notification that either:

(a) The submission was complete and ERCOT is reviewing the request; or

(b) The submission was incomplete. For incomplete submissions, ERCOT will:

(i) Identify the missing information; and

(ii) Provide instructions for the Requesting Entity to submit the missing information (e.g., to ERCOT Legal at MPRegistration@ercot.com or through the RIOO system).

(2) Unless otherwise agreed by ERCOT, not later than ten Business Days of receiving a notice of an incomplete submission, the Requesting Entity shall submit the missing information to ERCOT through the RIOO system or as otherwise directed by ERCOT or request additional time to provide the additional information with an explanation for the delay.

(3) Within seven days after ERCOT acknowledges receiving a complete request for extension, ERCOT shall designate an ERCOT senior representative with decision-making authority to participate in discussions with the Requesting Entity regarding the extension request.

(4) During the time ERCOT considers an extension request, ERCOT and the Requesting Entity will cooperate in requesting and providing relevant information to develop a complete record to allow an effective and efficient review process.

(5) ERCOT shall make reasonable efforts to complete or extension request process within 180 days after receiving a complete request for an extension. If ERCOT cannot complete its review of the request within that time period, ERCOT shall provide the Requesting Entity an estimate of the additional time needed to complete its review. ERCOT shall provide the Requesting Entity with written notification that ERCOT has completed its review and ERCOT's determination that the extension is:

(a) Approved;

(b) Approved in part, along with details of the approved part of the extension, and a detailed explanation for denying part of the extension request; or

(c) Rejected, along with details explaining the grounds upon which ERCOT rejected the extension request.

(6) Upon issuance of ERCOT's decision on an extension request, the Requesting Entity adversely affected may appeal ERCOT's decision to the Public Utility Commission of Texas (PUCT) pursuant to P.U.C. PROC. R. 22.251, Review of Electric Reliability Council of Texas (ERCOT) Conduct. For such an appeal, the Requesting Entity is not required to comply with Protocol Section 20, Alternative Dispute Resolution Procedure and Procedure for Return of Settlement Funds.

(7) A Requesting Entity that does not submit a notice of appeal to ERCOT within the required time period after receiving ERCOT's notice rejecting the extension request is deemed to have accepted ERCOT's decision.

2.13 Actions Following a Transmission-Connected Inverter-Based Resource (IBR), Type 1 Wind-powered Generation Resource (WGR) or Type 2 WGR Apparent Failure to Ride-Through

(1) The required ride-through performance criteria ("Required Criteria") are defined in Section 2.6.2.1, Frequency Ride-through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, and Section 2.9.1, Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs), Type 2 WGRs and Type 3 WGRs. For any Inverter-Based Resource (IBR), Type 1 Wind-powered Generation Resource (WGR) or Type 2 WGR with an approved exemption or extension for the ride-through requirements, the Resource's documented maximum ride-through capabilities are the ride-through performance requirements for compliance purposes for the duration of the exemption or extension unless otherwise indicated by Governmental Authority rules or regulations. All IBRs, Type 1 WGRs and Type 2 WGRs shall strive to meet or exceed the Required Criteria to the fullest extent their equipment allows.

(2) For any IBR, Type 1 WGR or Type 2 WGR with an approved exemption or extension for the ride-through requirements, the Resource's documented maximum ride-through capabilities are the ride-through performance requirements for compliance purposes for the duration of the exemption or extension unless otherwise indicated by Governmental Authority rules or regulations. Any IBR with documented maximized ride-through capabilities that exceed the applicable Required Criteria and fails to ride-through a disturbance within the IBR's documented maximized capabilities is also subject to this Section.

(3) If an IBR, Type 1 WGR or Type 2 WGR does not ride-through in accordance with the applicable ride-through performance requirements, including its maximized capabilities (an "Apparent Performance Failure"), the Resource Entity shall, as soon as practicable:

(a) Investigate the Apparent Performance Failure;

(b) Report to ERCOT the cause of the Apparent Performance Failure; and

(c) Perform model validation and report the results to ERCOT.

(4) Following an Apparent Performance Failure, Transmission Service Providers (TSPs) directly impacted by the Apparent Performance Failure shall provide available information to ERCOT to assist with event analysis.

(5) The Resource Entity for an IBR, Type 1 WGR, or Type 2 WGR that experiences an Apparent Performance Failure shall:

(a) Develop a plan to ensure the IBR, Type 1 WGR, or Type 2 WGR meets the applicable ride-through performance requirements (whether documented maximized capability or Required Criteria, whichever applies);

(b) Submit the plan to ERCOT for approval within 90 days; and

(c) If ERCOT approves the plan, implement the plan within 180 days, unless ERCOT approves a longer timeline.

(6) To encourage all Resources to maximize all equipment frequency and voltage ride-through parameters to the maximum level the equipment allows and all new Resources to also design the plant to the utilize the inverter or converter capabilities to the fullest extent, any Apparent Performance Failure where system conditions at the Point of Interconnection Bus (POIB) exceeded the Required Criteria but remained below documented maximized frequency or voltage ride-through capabilities exceeding the applicable requirements in Sections 2.6.2, Frequency Ride-Through Requirements for Generation Resources and Energy Storage Resources, 2.9.1, 2.9.1.1, Preferred Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), or 2.9.1.2, Legacy Voltage Ride-Through Requirements for Transmission-Connected Inverter-Based Resources (IBRs), Type 1 Wind-powered Generation Resources (WGRs) and Type 2 WGRs, shall be reported to the Reliability Monitor only if the Resource Entity does not fully meet the requirements in paragraphs (3) and (5) above.

2.14 Advanced Grid Support Requirements for Inverter-Based Resources (IBRs)

(1) An Energy Storage Resource (ESR) shall provide the following advanced grid support when within the inverter current limit:

(a) Meet the modeling requirements in Planning Guide Section 6.2, Dynamics Model Development, to demonstrate the capability to maintain an internal voltage phasor in the sub-transient-to-transient timeframe and control the voltage phasor to maintain synchronism with the ERCOT Transmission Grid.

(2) An ESR interconnected to the ERCOT Transmission Grid pursuant to an original Standard Generation Interconnection Agreement (SGIA) executed before April 1, 2026 is not required to comply with the requirements of this Section 2.14. Notwithstanding the prior sentence, the requirements of this Section 2.14 apply to those portions of any ESR modifications adding MW capacity, on an aggregate nameplate basis, on or after April 1, 2026.

ERCOT Nodal Operating Guides

Section 3: ERCOT and Market Participant Responsibilities

December 5, 2025

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3 ERCOT AND MARKET PARTICIPANT RESPONSIBILITIES

3.1 System Control Interfaces with ERCOT

3.1.1 Introduction

(1) This section defines the specific responsibilities between Qualified Scheduling Entities (QSEs) and Transmission Service Providers (TSPs) to support ERCOT in the security and reliability of the ERCOT System. Resource Entities may communicate directly with ERCOT under emergency and specific scheduling activities. All other Entities operating in ERCOT shall communicate with their appropriate QSE or TSP.

[NOGRR177: Replace paragraph (1) above with the following upon system implementation of NPRR857:]

(1) This section defines the specific responsibilities of Qualified Scheduling Entities (QSEs), Transmission Service Providers (TSPs), and Direct Current Tie Operators (DCTOs) to support ERCOT in the security and reliability of the ERCOT System. Resource Entities may communicate directly with ERCOT under emergency and specific scheduling activities. All other Entities operating in ERCOT shall communicate with their appropriate QSE or TSP.

3.1.2 Compliance with Dispatch Instructions

(1) Each QSE and Transmission Operator (TO) within the ERCOT System shall comply fully and promptly with valid Dispatch Instructions as specified in Protocol Section 6.5.7.9, Compliance with Dispatch Instructions.

3.1.3 Dispatch Instructions

(1) The following section applies only to Dispatch Instructions issued for Real-Time operations intended to change or preserve the state, status, output, or input of an element or facility of the ERCOT System.

(a) The following actions shall be taken by ERCOT and Market Participants upon the issuance and receipt of a Verbal Dispatch Instruction (VDI).

(i) When issuing a VDI, ERCOT shall take one of the following actions:

(A) Confirm the Market Participant’s response if the repeated VDI is correct;

(B) Reissue the VDI if the repeated VDI is incorrect or requested by the Market Participant; or

(C) Reissue the VDI or take an alternative action if the VDI was not understood by the Market Participant.

(ii) Each QSE, when re-issuing the ERCOT VDI to the appropriate Resource, shall take one of the following actions:

(A) Confirm the Resource's response if the repeated VDI is correct;

(B) Reissue the VDI if the repeated VDI is incorrect or requested by the Resource; or

(C) Coordinate an alternative action, as required in the ERCOT Protocols, with ERCOT if a response is not received or if the VDI was not understood by the Resource.

(iii) Each TO, when re-issuing the ERCOT VDI to the appropriate Distribution Service Provider (DSP) or Resource, shall take one of the following actions:

(A) Confirm the DSP's or Resource's response if the repeated VDI is correct;

(B) Reissue the VDI if the repeated VDI is incorrect or requested by the DSP or Resource; or

(C) Coordinate an alternative action with ERCOT, as required in the ERCOT Protocols, if a response is not received or if the VDI was not understood by the DSP or Resource.

[NOGRR177: Replace paragraph (iii) above with the following upon system implementation of NPRR857:]

(iii) Each TO, when re-issuing the ERCOT VDI to the appropriate Distribution Service Provider (DSP), DCTO, or Resource, shall take one of the following actions:

(A) Confirm the DSP's, DCTO's, or Resource's response if the repeated VDI is correct;

(B) Reissue the VDI if the repeated VDI is incorrect or requested by the DSP, DCTO, or Resource; or

(C) Coordinate an alternative action with ERCOT, as required in the ERCOT Protocols, if a response is not received or if the VDI was not understood by the DSP, DCTO, or Resource.

(b) After receipt of the VDI, the receiving Market Participant shall take one of the following actions:

(i) Repeat, not necessarily verbatim, the VDI and receive confirmation that the response was correct; or

(ii) Request that the VDI be reissued.

(c) When ERCOT initiates a Hotline VDI, ERCOT shall confirm that the VDI was received by at least one Market Participant on the Hotline call.

(d) When issuing or re-issuing a Dispatch Instruction, ERCOT, QSEs, and TOs shall specify the time using a 24-hour clock in Central Prevailing Time (CPT) if the Dispatch Instruction is not to be acted upon immediately.

(e) When issuing or re-issuing a Dispatch Instruction for Transmission Elements and Transmission Facilities, ERCOT, QSEs, and TOs shall utilize the nomenclature specified in the ERCOT Network Operations Model.

3.2 Qualified Scheduling Entities

3.2.1 Operating Obligations

(1) Qualified Scheduling Entities (QSEs) that are Wide Area Network (WAN) Participants shall maintain a control or operations center with qualified personnel with the authority to commit and bind the QSE, as described in Protocol Section 16.2, Registration and Qualification of Qualified Scheduling Entities. QSEs shall communicate with ERCOT for the purpose of meeting their obligations specified in the Protocols and these Operating Guides. Each QSE shall designate an Authorized Representative as defined in Protocol Section 2.1, Definitions.

(2) QSEs that are WAN Participants shall submit to ERCOT, by March 15 of each year, a written back-up control plan to continue operation of the control or operations center in the event the QSE's control or operations center becomes inoperable. Back-up control plans shall be submitted to ERCOT via secured webmail or encrypted data transfer. QSEs shall request that a secure email account be created with ERCOT by sending an email to shiftsupervisors@ercot.com.

(3) Each back-up control plan shall be reviewed and updated annually and shall include as a minimum, the following:

(a) Description of actions to be taken by QSE personnel to avoid placing a prolonged burden on ERCOT and other Market Participants, while operating in back-up control mode;

(b) Description of specific functions and responsibilities to be performed to continue operations from an alternate location;

(c) Procedures and responsibilities for maintaining basic voice communications capabilities with ERCOT; and

(d) Procedures for back-up control function testing and the training of personnel.

(4) As an option, the back-up control plan may include arrangements made with another Entity to provide the minimum back-up control functions in the event the QSE's primary functions are interrupted.

(5) For connectivity requirements for back-up sites, refer to Section 7, Telemetry and Communication.

3.2.2 Changes in Resource Status

(1) QSEs shall verbally notify ERCOT of unplanned changes in the status of a Resource as soon as practicable following the event as referenced in Protocol Section 6.5.5.1, Changes in Resource Status.

(2) QSEs shall verbally notify ERCOT and/or Transmission Service Provider (TSP) of equipment changes that affect the reactive capability of an operating Generation Resource or Energy Storage Resource (ESR).

(3) QSEs shall submit a Current Operating Plan (COP) in accordance with Protocol Section 3.9, Current Operating Plan (COP).

3.2.3 Regulatory Required Incident and Disturbance Reports

(1) In the event of a system incident or disturbance, as described by North American Electric Reliability Corporation (NERC) and the Department of Energy (DOE), QSEs, and TSPs or their Designated Agents shall provide required reports to ERCOT, the DOE and/or NERC. Types of incidents or disturbances which may trigger these reporting requirements are:

[NOGRR177: Replace paragraph (1) above with the following upon system implementation of NPRR857:]

(1) In the event of a system incident or disturbance, as described by North American Electric Reliability Corporation (NERC) and the Department of Energy (DOE), QSEs, TSPs, and Direct Current Tie Operators (DCTOs), or their Designated Agents, shall provide

required reports to ERCOT, the DOE and/or NERC. Types of incidents or disturbances which may trigger these reporting requirements are:

(a) Uncontrolled loss of Load;

(b) Load shed events;

(c) Public appeal for reduced use of electricity;

(d) Actual or suspected attacks on the transmission system;

(e) Vandalism;

(f) Actual or suspected cyber attacks;

(g) Fuel supply emergencies;

(h) Loss of electric service to large customers;

(i) Loss of bulk transmission component that significantly reduces integrity of the transmission system;

(j) Islanding of transmission system;

(k) Sustained voltage excursions;

(l) Major damage to power system components; and

(m) Failure, degradation or misoperation of Remedial Action Schemes (RASs) or other operating systems.

(2) Full descriptions of the DOE and NERC reports are available on their respective websites.

3.2.4 Ancillary Service Qualification and Testing Program

(1) Resources designated to provide Ancillary Services must qualify with ERCOT prior to participation in the Ancillary Service market.

(2) ERCOT shall reject offers to provide Ancillary Services received from an unqualified Resource and shall notify the appropriate QSE that the Resource is not qualified.

(3) ERCOT, at its sole discretion, may provisionally qualify Load Resources to provide Ancillary Services, without completion of a qualification test, for 90 days.

(4) ERCOT shall evaluate the actual performance of all Resources providing Ancillary Services in accordance with Protocol Section 8, Performance Monitoring. ERCOT shall

notify the QSE of a Resource failing to meet the performance requirements as specified in Protocol Section 8. A Resource failing to meet the performance requirements for two consecutive months shall be required to develop and implement a corrective action plan to address its failure as specified in Protocol Section 8.4, ERCOT Response to Market Non-Performance.

(5) ERCOT shall, in accordance with Protocol Section 8.4, revoke the qualification to provide Ancillary Services for any Resource failing an Ancillary Service performance standard for four consecutive months.

(6) Any Resource with a revoked Ancillary Service qualification may be re-tested at the sole discretion of ERCOT only after demonstrating and implementing a corrective action plan as described in Protocol Section 8.4.

3.3 Resource Entities

(1) The operation of a Generation Resource and Energy Storage Resource (ESR) shall conform to the requirements of the Protocols, North American Electric Reliability Corporation (NERC) Reliability Standards and these Operating Guides. As prescribed in Protocol Sections, 3.7.1.1, Generation Resource Parameters, 3.7.1.2, Load Resource Parameters, 3.7.1.3, Energy Storage Resource Parameters, and 3.10.7.2, Modeling of Resources and Transmission Loads, the Qualified Scheduling Entities (QSEs) and Resource Entities shall provide ERCOT and the Transmission Service Provider (TSP) with modeling information describing each Generation Resource, ESR, and Load Resource.

(2) As prescribed in Protocol Section 3.10.7.1.4, Transmission, Main Power Transformers (MPTs) and Generation Resource Step-Up Transformers, Resource Entities will provide information on these transformers to TSPs.

(3) As prescribed in Protocol Sections 3.10.7.5, Telemetry Requirements, 6.5.5.2, Operational Data Requirements, and 8, Performance Monitoring, the QSE reporting for a Resource Entity shall provide operational information for generation facilities greater than 10 MW.

(4) At a minimum, a Resource Entity shall notify ERCOT and the QSE of the following:

(a) 60 days prior to implementation of any planned equipment changes that affect the reactive capability of an operating Generation Resource or ESR.

(b) Any such changes that decrease the reactive capability of the Generation Resource or ESR below the required level and changes that decrease the voltage ride-through capability of the Resource must be approved by ERCOT prior to implementation;

(c) As soon as practicable when high reactive loading or reactive oscillations on Generation Resources or ESRs are observed; and

(d) As soon as practicable when a Generation Resource or ESR trips Off-Line due to voltage or reactive problems.

(5) When scheduled to ERCOT, Resource Entities shall be staffed or monitored 24x7, by personnel capable of making operating decisions. Each Resource Entity shall designate an Authorized Representative as defined in Protocol Section 2.1, Definitions. This applies to all:

(a) Generation Resources or ESR greater than 10 MW; and

(b) Load Resources.

(6) The Resource Entity shall implement the following in a reliable and safe manner and in accordance with the switching procedure of the directly connected TSP:

(a) Synchronizing of the generation to the ERCOT System; and

(b) Transmission switchyard switching or clearances.

(7) Any Resource or Customer-owned switching device that can interrupt flow through network transmission equipment, 60 kV or greater in nominal voltage, must have an agreement with the Transmission Operator (TO) to schedule Outages on, and perform emergency switching of, the device.

(8) The Generation Resource or ESR specifically licensed by a federal regulatory agency shall, through its QSE representative, provide any applicable grid interconnection and performance licensing requirements to ERCOT and the TSP to which the licensee is connected.

(9) The TSP is obligated to incorporate any such licensing requirements into its planning and operations, and ERCOT shall support such requirements. Both ERCOT and the TSP will create necessary procedures for satisfying these requirements. Such procedures will include provisions to notify the facility licensee through its QSE of any requirements that cannot be satisfied.

(10) Any proposal for revision of this Operating Guide and the procedures incorporating the licensee requirements that would diminish the obligation or ability of ERCOT or the TSP to support these requirements shall be provided to the licensee through its QSE to afford it an opportunity for review and response. Any such proposal that is approved, as a result of which the licensee is required to implement changes to meet its license requirements or to seek amendment to its license, shall become effective no sooner than six months following the approval.

(11) Resource Entities must provide Resource-owned Transmission Elements data requirements as prescribed in Protocol Section 3.10.7, ERCOT System Modeling Requirements. Additional distribution voltage level devices and connectivity may be required as well to adequately represent the modeling of the Resource within ERCOT computer systems.

3.3.1 Unit Capability Requirements

(1) In the event that a QSE fails to meet Protocol Section 8.1.1.2, General Capacity Testing Requirements, which requires Seasonal unit capability reporting and testing, ERCOT shall provide this QSE with Notice of its failure to meet the Protocols. This Notice shall be sent to the primary contact of the QSE representing the Generation Resource or ESR via email. In addition to this written Notice, ERCOT shall make a reasonable effort to notify the QSE via telephone.

(2) ERCOT shall allow the QSE three days to correct the omission by submitting ERCOT approved test results. If the Resource in question is operated during these three days, and no test results are provided to ERCOT, then the QSE shall be disqualified from provision of Ancillary Services.

(3) If the Resource is not operated and included in a QSE Current Operating Plan (COP) after the notification of the Protocol violation, then ERCOT shall not disqualify the Ancillary Service provider unless or until the Resource is operated and included in the COP that might be depended upon for Ancillary Services.

3.3.2 Unit Reactive Capability Requirements

3.3.2.1 Corrected Unit Reactive Limits (CURL)

(1) A reactive capability curve and associated data for each unit on the ERCOT System shall be submitted to ERCOT through the Market Information System (MIS) Certified Area and must contain the most limiting elements for the leading and lagging reactive output. The limiting factors such as under-excitation limiters, over-excitation limiters, ambient temperature limitations across the MW range of the unit at the unit terminals or any other factor that limits the reactive output of the unit and is verifiable through engineering calculations or testing shall be updated and provided on the corrected reactive capability curve. The corrected reactive capability curve establishes the Corrected Unit Reactive Limits (CURL) at the unit terminals that ERCOT Planning and ERCOT Operations, and TSPs will use for their studies. For Intermittent Renewable Resources (IRRs) the CURL data shall be reported at the low side of the MPT. Resources will provide these updated curves and associated test data to ERCOT by submitting test information to the Net Dependable Capability and Reactive Capability (NDCRC) application located on the MIS Secure Area. Once approved by ERCOT per Section 3.5, ERCOT Implementation, Resources will provide updated data by submitting changes to the appropriate ERCOT Resource Registration information in accordance with Planning Guide Section 6.8, Resource Registration Procedures. Prior to including the submitted data into the Network Operations Model, ERCOT will notify the TSP to which the Resource Entity is interconnected that the test data is posted on the MIS Secure Area. ERCOT and TSPs may review the data and provide any comments within ten Business Days. ERCOT will include these changes in the future Network Operations Model and forward the changes to the TSPs and the Steady State Working Group (SSWG) for use in their studies. The CURL should be available in the Resource Entities' control room where the tests are

conducted and at the QSE's Real-Time generation dispatch desk. During any test, the Generation Resource must maintain its generator cooling system at normal operating conditions, the Automatic Voltage Regulator (AVR) in service and all auxiliary equipment in service that is needed for expected normal operation.

NOGRR204: Replace Section 3.3.2.1 above with the following upon system implementation of NPRR989:]

3.3.2.1 Corrected Unit Reactive Limits (CURL)

(1) A reactive capability curve and associated data for each unit on the ERCOT System shall be submitted to ERCOT through the Market Information System (MIS) Certified Area and must contain the most limiting elements for the leading and lagging reactive output. The limiting factors such as under-excitation limiters, over-excitation limiters, ambient temperature limitations across the MW range of the unit at the unit terminals or any other factor that limits the reactive output of the unit and is verifiable through engineering calculations or testing shall be updated and provided on the corrected reactive capability curve. The corrected reactive capability curve establishes the Corrected Unit Reactive Limits (CURL) at the unit terminals that ERCOT Planning and ERCOT Operations, and TSPs will use for their studies. For Intermittent Renewable Resources (IRRs) the CURL data shall be reported at the low side of the MPT. Resources will provide these updated curves and associated test data to ERCOT by submitting test information to the Net Dependable Capability and Reactive Capability (NDCRC) application located on the MIS Secure Area. Once approved by ERCOT per Section 3.5, ERCOT Implementation, Resources will provide updated data by submitting changes to the appropriate ERCOT Resource Registration information in accordance with Planning Guide Section 6.8, Resource Registration Procedures. Prior to including the submitted data into the Network Operations Model, ERCOT will notify the TSP to which the Resource Entity is interconnected that the test data is posted on the MIS Secure Area. ERCOT and TSPs may review the data and provide any comments within ten Business Days. ERCOT will include these changes in the future Network Operations Model and forward the changes to the TSPs and the Steady State Working Group (SSWG) for use in their studies. The CURL should be available in the Resource Entities' control room where the tests are conducted and at the QSE's Real-Time generation dispatch desk. During any test, the Generation Resource or ESR must maintain its generator cooling system at normal operating conditions, the Automatic Voltage Regulator (AVR) in service and all auxiliary equipment in service that is needed for expected normal operation.

3.3.2.2 Reactive Testing Requirements

(1) Reactive testing may be performed as either "Coordinated," or "Non-Coordinated," the difference being the amount of notification provided to ERCOT and the TO, and level of their involvement in testing.

(a) Coordinated Testing

(i) Coordinated testing is the preferred method for new or larger-capacity units, as it provides a greater amount of coordination with ERCOT and the TO, allowing testing impacts and any potential adjustments to local voltage levels to be studied in advance.

(ii) The Resource Entity requesting a Coordinated test must submit a test request to ERCOT and the TO via their QSE, by no later than 15:00, one day prior to the proposed test date. ERCOT and the TO then have until 17:00 of the day prior to the proposed test date, to either approve or disapprove the test request.

(iii) Both ERCOT and the TO have the right to deny or cancel a test at any time, if they feel that system reliability may be adversely impacted by the test.

(iv) The test requests should contain the proposed time and date of the test, type of test (leading or lagging), expected unit MW and MVAr output range during the test, and a copy of the reactive capability curve.

(b) Non-Coordinated Testing

(i) The Resource Entity representing the resource requesting a Non-Coordinated test must inform ERCOT and the TO via their QSE at least two hours prior to the proposed start of the test.

(ii) Both ERCOT and the TO have the right to deny or cancel a test at any time, if they feel that system reliability may be adversely impacted by the test.

(2) Lagging Reactive Testing

(a) It is recommended, but not required, that lagging reactive tests be performed when system voltage is within the voltage profile, such as during high load periods.

(b) Lagging tests should meet the following performance criteria:

(i) Lagging Test 1: Test at or above 95% of the unit's High Sustained Limit (HSL) for at least 15 minutes. IRRs should test at or above 60% of their HSL. Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(ii) Lagging Test 2: Test at the unit's HSL for at least one hour. IRRs should test with at least 90% of photovoltaic inverters or wind turbines on-line. Testing acceptance criteria is met if the unit achieved at least 50% of the units CURL for one hour.

(iii) Lagging Test 3: Test at the unit's normally expected minimum real power output during system light load conditions for at least one minute. IRRs and nuclear units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(3) Leading Reactive Testing

(a) It is recommended, but not required, that leading reactive tests be performed when system voltage is within the voltage profile, such as during low load periods.

(b) Leading tests should meet the following performance criteria:

(i) Leading Test 1: Test at the unit's normally expected maximum real power output during system light load conditions for at least 15 minutes. IRRs should test at or below 60% of their HSL. Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's original manufacturer reactive curve or most recent CURL.

(ii) Leading Test 2: Test at the unit's HSL for at least one minute. IRR units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(iii) Leading Test 3: Test at the unit's normally expected minimum real power output during system light load conditions for at least one minute. IRRs and nuclear units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(4) The Resource Entity shall measure the tested reactive capability on the generator output terminals for non-IRR Generation Resources. The value recorded shall represent the gross MVAr output of the Generation Resource. Additionally, the net reactive capability shall be measured at the high side of the GSU transformer and at the POIB, if metering is available. The high side values shall have the Generation Resource's auxiliary reactive consumption and the GSU losses deducted from the Generation Resource's gross reactive output. The POIB values shall have the plant's auxiliary load and any additional load deducted from the Generation Resource's gross reactive output. If metering is not available at the high side, the Resource Entity shall calculate the reactive capability at the high side and at the POIB. These values are required and must be submitted through the MIS Certified Area. CURLs shall be attached to the test results submitted, and shall be clearly defined. All applicable test data shall be submitted on the form in the NDCRC application.

(5) The QSE representing a Generation Resource shall be responsible for scheduling reactive verification tests when requested by the Resource Entity in accordance with the conditions outlined above. If ERCOT does not issue a specific request for a Generation Resource reactive capability verification, the Generation Resource shall complete a reactive verification test at least every five years.

(6) ERCOT shall have the option to waive the requirement to perform Leading Test 1 for any Generation Resource that seldom runs during such light Load periods. The granting of such a waiver shall be effective for five years.

(7) The Resource Entity representing a Generation Resource shall be responsible for the timely and accurate reporting of test results to ERCOT and to the QSE representing the Generation Resource. The Resource Entity representing a Generation Resource must properly complete all required data fields in the NDCRC application for a test to be considered valid.

[NOGRR204: Replace Section 3.3.2.2 above with the following upon system implementation of NPRR989:]

3.3.2.2 Reactive Testing Requirements

(1) Reactive testing may be performed as either "Coordinated," or "Non-Coordinated," the difference being the amount of notification provided to ERCOT and the TO, and level of their involvement in testing.

(a) Coordinated Testing

(i) Coordinated testing is the preferred method for new or larger-capacity units, as it provides a greater amount of coordination with ERCOT and the TO, allowing testing impacts and any potential adjustments to local voltage levels to be studied in advance.

(ii) The Resource Entity requesting a Coordinated test must submit a test request to ERCOT and the TO via their QSE, by no later than 15:00, one day prior to the proposed test date. ERCOT and the TO then have until 17:00 of the day prior to the proposed test date, to either approve or disapprove the test request.

(iii) Both ERCOT and the TO have the right to deny or cancel a test at any time, if they feel that system reliability may be adversely impacted by the test.

(iv) The test requests should contain the proposed time and date of the test, type of test (leading or lagging), expected unit MW and MVAr output range during the test, and a copy of the reactive capability curve.

(b) Non-Coordinated Testing

(i) The Resource Entity representing the resource requesting a Non-Coordinated test must inform ERCOT and the TO via their QSE at least two hours prior to the proposed start of the test.

(ii) Both ERCOT and the TO have the right to deny or cancel a test at any time, if they feel that system reliability may be adversely impacted by the test.

(2) Lagging Reactive Testing

(a) It is recommended, but not required, that lagging reactive tests be performed when system voltage is within the voltage profile, such as during high load periods.

(b) For Generation Resources, lagging tests should meet the following performance criteria:

(i) Lagging Test 1: Test at or above 95% of the unit's High Sustained Limit (HSL) for at least 15 minutes. IRRs should test at or above 60% of their HSL. Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(ii) Lagging Test 2: Test at the unit's HSL for at least one hour. IRRs should test with at least 90% of photovoltaic inverters or wind turbines on-line. Testing acceptance criteria is met if the unit achieved at least 50% of the units CURL for one hour.

(iii) Lagging Test 3: Test at the unit's normally expected minimum real power output during system light load conditions for at least one minute. IRRs, ESRs, and nuclear units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(c) For inverter-based ESRs, lagging tests should meet the following performance criteria:

(i) Lagging Test 1a: Test at or above 95% the unit's Maximum Operating Discharge Power Limit for at least 15 minutes or entire duration if less than 15 minutes.

Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(ii) Lagging Test 1b: Test at or above 95% of the unit's Maximum Operating Charge Power Limit for at least 15 minutes or entire duration if less than 15 minutes.

Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(iii) Lagging Test 2: Test with at least 90% of the ESR's inverters On-Line for at least one hour. Testing acceptance criteria is met if the unit achieved at least 50% of its CURL for 1 hour at any MW level.

(3) Leading Reactive Testing

(a) It is recommended, but not required, that leading reactive tests be performed when system voltage is within the voltage profile, such as during low load periods.

(b) For Generation Resources, leading tests should meet the following performance criteria:

(i) Leading Test 1: Test at the unit's normally expected maximum real power output during system light load conditions for at least 15 minutes. IRRs should test at or below 60% of their HSL. Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's original manufacturer reactive curve or most recent CURL.

(ii) Leading Test 2: Test at the unit's HSL for at least one minute. IRR units and ESRs are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(iii) Leading Test 3: Test at the unit's normally expected minimum real power output during system light load conditions for at least one minute. IRRs and nuclear units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(c) For ESRs leading tests should meet the following performance criteria:

(i) Leading Test 1a: Test at or above 95% of the unit's Maximum Operating Discharge Power Limit for at least 15 minutes or entire duration if less than 15 minutes.

Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(ii) Leading Test 1b: Test at or above 95% of the unit's Maximum Operating Charge Power Limit for at least 15 minutes or entire duration if less than 15 minutes.

Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(4) The Resource Entity shall measure the tested reactive capability on the generator output terminals for non-IRR Generation Resources. The value recorded shall represent the gross MVAr output of the Generation Resource or ESR. Additionally, the net reactive capability shall be measured at the high side of the GSU transformer and at the POIB, if metering is available. The high side values shall have the Generation Resource's or

ESR's auxiliary reactive consumption and the GSU losses deducted from the Generation Resource's or ESR's gross reactive output. The POIB values shall have the plant's auxiliary load and any additional load deducted from the Resource's gross reactive output. If metering is not available at the high side, the Resource Entity shall calculate the reactive capability at the high side and at the POIB. These values are required and must be submitted through the MIS Certified Area. CURLs shall be attached to the test results submitted, and shall be clearly defined. All applicable test data shall be submitted on the form in the NDCRC application.

(5) The QSE representing a Generation Resource or ESR shall be responsible for scheduling reactive verification tests when requested by the Resource Entity in accordance with the conditions outlined above. If ERCOT does not issue a specific request for a Generation Resource or ESR reactive capability verification, the Generation Resource or ESR shall complete a reactive verification test at least every five years.

(6) ERCOT shall have the option to waive the requirement to perform Leading Test 1 for any Generation Resource or ESR that seldom runs during such light Load periods. The granting of such a waiver shall be effective for five years.

(7) The Resource Entity representing a Generation Resource or ESR shall be responsible for the timely and accurate reporting of test results to ERCOT and to the QSE representing the Generation Resource or ESR. The Resource Entity representing a Generation Resource or ESR must properly complete all required data fields in the NDCRC application for a test to be considered valid.

3.3.3 Resource Entity Responsibilities for Equipment Ratings

(1) Resource Entities that own Transmission Facilities are responsible for determining the Ratings of its Transmission Facilities and shall send the methodology used to ERCOT in accordance with the Protocols. Technical limits established for the operation of Transmission Facilities and associated equipment shall be applied consistently in engineering and planning studies, Real-Time security analyses, and operator actions.

(2) Resource Entity owners of Transmission Facilities shall provide to ERCOT all nominal Transmission Facility Ratings.

(3) In operating the ERCOT Transmission Grid, ERCOT shall use these Ratings as follows:

(a) ERCOT shall limit pre-contingency flows to enforce the Normal Rating.

(b) If an approved Remedial Action Plan (RAP) is unavailable to unload the Transmission Facility post-contingency, ERCOT shall control the post-contingency loading of the Transmission Facility to levels below the Emergency Rating. The enforcement shall be implemented in a manner such that the post-contingency loading will be at, or below, Normal Rating within two hours.

(c) If an approved RAP is available, ERCOT shall control the post-contingency loading of the Transmission Facility to levels below the 15-Minute Rating. The RAP shall be implemented in a manner such that the RAP post-implementation loading will be at, or below, the Emergency Rating within 15 minutes and subsequently, at or below, Normal Rating within two hours.

(d) ERCOT shall use best efforts to restore all Transmission Facilities to within Normal Ratings as soon as practicable, based on Good Utility Practice.

3.4 Load Resource Testing Requirement

(1) After initial qualification, a Load Resource's telemetry shall be evaluated annually and applicable relay functionality will be tested and validated by ERCOT every 24 months as required by these Operating Guides. In addition, ERCOT shall annually verify the telemetry attributes of each Load Resource providing ERCOT Contingency Reserve Service (ECRS) or Responsive Reserve (RRS) using high-set under-frequency relay. If a Load Resource fails to provide the appropriate documents as required in the annual and biennial verification test for two consecutive years, ERCOT shall notify the associated Qualified Scheduling Entity (QSE) of non-compliance. After a 30-day allowance for the deficiency to be corrected, ERCOT shall reduce the Resource's ability to provide Ancillary Services in the ERCOT market to zero.

3.5 ERCOT Implementation

(1) Reactive test results shall be reviewed by ERCOT to validate the accuracy and consistency of the test data provided, and to determine the appropriateness of unit loading and system conditions during the test. ERCOT shall have the right to order a re-test of the unit, if it determines there are significant discrepancies with the test data.

(2) Reactive test results shall be reviewed by ERCOT to determine if test results met the acceptance criteria of Section 3.3.2.2, Reactive Testing Requirements. If the test results fail to meet the acceptance criteria of Section 3.3.2.2, ERCOT shall have the right to either order the Resource Entity to produce a new Corrected Unit Reactive Limit (CURL), or to order a re-test of the unit.

(3) Reactive test results shall be reviewed by ERCOT against the most recent CURL for the unit. If unit reactive capability appears to fail the acceptance criteria of Section 3.3.2.2, ERCOT shall contact the Resource Entity and attempt to resolve the limitation. ERCOT shall have the right to order the Resource Entity to produce a new CURL that reflects current operating limits.

(4) Any new CURL produced by a Resource Entity in response to new operating limits, shall be submitted by the Resource Entity via the Resource Registration process within four weeks of ERCOT's approval of the test. ERCOT will notify Transmission Service Providers (TSPs) after Resource Registration information submittal as described in Section 3.3.2.1, Corrected Unit Reactive Limits (CURL).

3.6 Transmission Service Providers

(1) ERCOT and Transmission Service Providers (TSPs) shall operate the ERCOT Transmission Grid in compliance with Good Utility Practice, North American Electric Reliability Corporation (NERC) Reliability Standards, Protocols and Operating Guides.

(2) TSPs shall designate an Authorized Representative as defined in Protocol Section 2.1, Definitions.

(3) Each TSP, at its own expense, may obtain Operating Period data from ERCOT.

[NOGRR177: Replace Section 3.6 above with the following upon system implementation of NPRR857:]

3.6 Transmission Service Providers and Direct Current Tie Operators

(1) ERCOT, Transmission Service Providers (TSPs), and Direct Current Tie Operators (DCTOs) shall operate the ERCOT Transmission Grid in compliance with Good Utility Practice, North American Electric Reliability Corporation (NERC) Reliability Standards, Protocols and Operating Guides.

(2) Each TSP, at its own expense, may obtain Operating Period data from ERCOT.

3.7 Transmission Operators

(1) Transmission Operators (TOs) shall follow ERCOT instructions:

(a) Performing the physical operation of the ERCOT Transmission Grid, including circuit breakers, switches, voltage control equipment, protective relays, metering and Load shedding equipment;

(b) Directing changes in the operation of transmission voltage control equipment per Section 2.7.3, Real-Time Operational Voltage Control;

(c) Managing Voltage Profiles established by ERCOT and Voltage Set Points per Section 2.7.3;

(d) Taking those additional actions required to prevent an imminent Emergency Condition or to restore the ERCOT Transmission Grid to a secure state in the event of a system emergency; and

(e) In response to a System Operating Limit (SOL) exceedance communicated by ERCOT.

(2) TOs must meet all requirements identified in the Protocols for TOs in addition to those requirements stated below for all Transmission Facilities represented:

(a) Monitor system conditions and notify ERCOT when Transmission Facility elements reach maximum safe operating limits as soon as practicable;

(b) Notify ERCOT of any changes in its Transmission Facility status within ten seconds of the change of status as specified in Protocol Section 3.10.7.5, Telemetry Requirements;

(c) Operate and manage Transmission Facilities between energy sources and the point of delivery;

(d) Coordinate emergency communications between a represented Transmission Service Provider (TSP) system and ERCOT;

[NOGRR177: Replace paragraph (d) above with the following upon system implementation of NPRR857:]

(d) Coordinate emergency communications between a represented Transmission Service Provider (TSP) or Direct Current Tie Operator (DCTO) system and ERCOT;

(e) Monitor the loading of the transmission system(s);

(f) Notify ERCOT of all changes to the status of all Transmission Elements and Transmission Facilities;

(g) Act as Single Point of Contact for transmission Outages;

(h) Maintain continuous communication (24x7) with ERCOT;

(i) Ensure Dispatch Instructions, received for their system or on behalf of represented TSPs or Distribution Service Providers (DSPs), are carried out as issued;

[NOGRR177: Replace paragraph (i) above with the following upon system implementation of NPRR857:]

(i) Ensure Dispatch Instructions, received for their system or on behalf of represented TSPs, DCTOs, or Distribution Service Providers (DSPs), are carried out as issued;

(j) Maintain operational metering;

(k) Implement Black Start;

(l) Ensure the ability to receive pre- and post-contingency system operating limit exceedances communicated by ERCOT through at least one of the following methods at all times, unless both systems are unavailable:

(i) Postings on the Market Information System (MIS) Secure Area; or

(ii) The GridGeo application.

Upon observation of a failure of the method that is being utilized, the TO will notify ERCOT as soon as practicable;

(m) Ensure the ability to monitor Generic Transmission Limits (GTLs) and the associated flows that affect their system via the Inter-Control Center Communications Protocol (ICCP); and

(n) Monitor GTLs and the associated flows that affect their system.

(3) TOs shall submit to ERCOT, by March 15 of each year, a written back-up control plan to continue operation in the event the TOs control center becomes inoperable. Back-up control plans shall be submitted to ERCOT via secured webmail or encrypted data transfer. TOs shall request that a secure email account be created with ERCOT by sending an email to shiftsupervisors@ercot.com.

(4) Each back-up control plan shall be reviewed and updated annually and shall meet the following minimum requirements:

(a) Include descriptions of actions to be taken by TO personnel to avoid placing a prolonged burden on ERCOT and other Market Participants;

(b) Include descriptions of specific functions and responsibilities to be performed to continue operations from an alternate location;

(c) Include procedures and responsibilities for maintaining basic voice communications capabilities with ERCOT; and

(d) Include procedures for back-up control function testing and the training of personnel.

(5) As an option, the back-up control plan may include arrangements made with another Entity to provide the minimum back-up control functions in the event the TO's primary functions are interrupted.

(6) By February 15 of each year, each TO shall submit to ERCOT its emergency operations plan to mitigate operating emergencies, as required by the applicable North American Electric Reliability Corporation (NERC) Reliability Standards, and in accordance with Section 8, Attachment L, Emergency Operations Plan. The emergency operations plan shall be submitted to ERCOT via secured webmail or encrypted data transfer. A TO may request a secure email account by sending an email to ERCOT at transrep@ercot.com. If

no changes have been made from the previous submission, the TO shall resubmit the emergency operations plan with a new revision date indicating that it has been reviewed and no changes were made. If a TO revises its emergency operations plan, the TO shall submit the revised emergency operations plan to ERCOT within 45 calendar days of the effective date of the revised plan and must include a summary of revisions.

(7) ERCOT shall review each TO's emergency operations plan to ensure it addresses all relevant reliability risks and will notify the TO of its conclusions within 30 calendar days of receipt of a TO's new or revised emergency operations plan. ERCOT shall coordinate with the TO on a mutually agreeable time frame for the resubmittal of the emergency operations plan if ERCOT determines that reliability concerns require revision to the emergency operations plan. Plans submitted for the annual review before February 15 will be deemed to have been received on February 15 for ERCOT to initiate the review described in this Section.

3.7.1 Transmission Owner Responsibility for a Vegetation Management Program

(1) Each transmission owner shall have a vegetation management program outlining procedures to prevent transmission line contact with vegetation. The transmission owner shall maintain documentation to verify the performance of the vegetation management program and shall provide that documentation to their respective TO and ERCOT upon request.

3.7.2 Transmission Service Provider Responsibilities for Equipment Ratings

(1) TSPs that own Transmission Facilities are responsible for determining the Ratings of their Transmission Facilities and shall send the methodology used to ERCOT in accordance with the Protocols. Technical limits established for the operation of Transmission Facilities and associated equipment shall be applied consistently in engineering and planning studies, Real-Time security analyses, and operator actions.

(2) TSPs owners of Transmission Facilities shall provide to ERCOT all nominal Transmission Facility Ratings.

(3) In operating the ERCOT Transmission Grid, ERCOT shall use these Ratings as follows:

(a) ERCOT shall limit pre-contingency flows to enforce the Normal Rating.

(b) If an approved Remedial Action Plan (RAP) is unavailable to unload the Transmission Facility post-contingency, ERCOT shall control the post-contingency loading of the Transmission Facility to levels below the Emergency Rating.

(c) If an approved RAP is available, ERCOT shall control the post-contingency loading of the Transmission Facility to levels below the 15-Minute Rating. The RAP shall be implemented in a manner such that the RAP post-implementation loading will be at, or below, the Emergency Rating within 15 minutes and subsequently at or below Normal Rating within two hours.

(d) ERCOT shall use best efforts to restore all Transmission Facilities to within Normal Ratings as soon as practicable, based on Good Utility Practice.

[NOGRR177: Replace Section 3.7.2 above with the following upon system implementation of NPRR857:]

3.7.2 Transmission Service Provider and Direct Current Tie Operator Responsibilities for Equipment Ratings

(1) TSPs and DCTOs that own Transmission Facilities are responsible for determining the Ratings of their Transmission Facilities and shall send the methodology used to ERCOT in accordance with the Protocols. Technical limits established for the operation of Transmission Facilities and associated equipment shall be applied consistently in engineering and planning studies, Real-Time security analyses, and operator actions.

(2) TSPs and DCTOs that own Transmission Facilities shall provide to ERCOT all nominal Transmission Facility Ratings.

(3) In operating the ERCOT Transmission Grid, ERCOT shall use these Ratings as follows:

(a) ERCOT shall limit pre-contingency flows to enforce the Normal Rating.

(b) If an approved Remedial Action Plan (RAP) is unavailable to unload the Transmission Facility post-contingency, ERCOT shall control the post-contingency loading of the Transmission Facility to levels below the Emergency Rating.

(c) If an approved RAP is available, ERCOT shall control the post-contingency loading of the Transmission Facility to levels below the 15-Minute Rating. The RAP shall be implemented in a manner such that the RAP post-implementation loading will be at, or below, the Emergency Rating within 15 minutes and subsequently at or below Normal Rating within two hours.

(d) ERCOT shall use best efforts to restore all Transmission Facilities to within Normal Ratings as soon as practicable, based on Good Utility Practice.

3.8 Requirements for Reporting Sabotage Information

(1) ERCOT Entities shall notify their designated Transmission Operator (TO) or Qualified Scheduling Entity (QSE) when experiencing disturbances or unusual occurrences suspected or determined to be caused by sabotage. Disturbances and unusual occurrences related to bulk electric system Facilities within the ERCOT Region are the only Facilities

subject to reporting. ERCOT Entities shall have procedures for the recognition of sabotage events on its Facilities and multi-site sabotage.

(2) TOs or QSEs shall inform ERCOT of disturbances or unusual occurrences suspected or determined to be caused by sabotage. TOs or QSEs may notify ERCOT by telephone or by email at shiftsupervisors@ercot.com.

(3) TOs and QSEs may inform other ERCOT Entities of the event(s), if, in the opinion of the TO or QSE, the situation impacts other Entities.

(4) ERCOT may inform TOs and QSEs of the event(s), if, in the opinion of ERCOT, the situation impacts ERCOT System reliability.

(5) ERCOT shall inform North American Electric Reliability Corporation (NERC) and governmental agencies of disturbances or unusual occurrences suspected or determined to be caused by sabotage in accordance with current laws and regulations. This is in addition to the report submitted by the NERC registered Entity.

ERCOT Nodal Operating Guides

Section 4: Emergency Operation

December 5, 2025

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4 EMERGENCY OPERATIONS

4.1 Introduction

(1) Emergency operation is intended to address operating conditions under which the reliability of the ERCOT System is inadequate and there is no solution readily apparent. During a declared system emergency, ERCOT can instruct Transmission Operators (TOs) and Qualified Scheduling Entities (QSEs) to take specific operating actions that would otherwise be discretionary. Upon receiving a Verbal Dispatch Instruction (VDI) from ERCOT, and in compliance with these Operating Guides, the QSEs shall direct relevant Resources or groups of Resources to respond to the instruction. ERCOT shall coordinate with QSEs and TOs to assure that necessary actions are taken to maintain reliability.

(2) It is essential that good, timely, and accurate communication routinely occur between ERCOT, TOs, and QSEs. QSE and TO personnel shall report unplanned equipment status changes as outlined in this Section. ERCOT System Operators may ask for status updates as required in order to gather information to make decisions on system conditions to determine what type of emergency communication may be appropriate.

(3) ERCOT may issue communications in the form of Operating Condition Notices (OCNs), Advisories, Watches and Emergency Notices. These communications may relate to but are not limited to, weather, transmission, computer failure, or generation information. ERCOT shall specify the severity of the situation, the area affected, the areas potentially affected, and the anticipated duration of the Emergency Condition. These communications will be issued by ERCOT to inform all TOs and QSEs of the current operating situation. TOs will notify their represented Transmission Service Providers (TSPs) and Load Serving Entities (LSEs). QSEs will in turn notify the appropriate Resources, Retail Electric Providers (REPs) and LSEs. QSEs and TOs shall establish and maintain internal procedures for contingency preparedness or to expedite the resolution of the conditions communicated by ERCOT that threaten system reliability.

(4) Before deciding which communication to issue, ERCOT must consider the possible severity of the operating situation before an Emergency Condition occurs. If practicable, the market shall be allowed to attempt to mitigate or eliminate any possible Emergency Condition. ERCOT has the responsibility to issue the appropriate communications to facilitate a solution by Market Participants.

4.2 Communication Prior to and During Emergency Conditions

4.2.1 Operating Condition Notice

(1) An Operating Condition Notice (OCN) shall be issued by ERCOT in accordance with Protocol Section 6.5.9.3.1, Operating Condition Notice. OCNs are for communication purposes only.

(2) ERCOT may require information from Qualified Scheduling Entities (QSEs) and Transmission Operators (TOs). Typical information requested may include, but is not limited to:

(a) Resource fuel capabilities;

(b) Resource condition details; and

(c) Actual weather conditions.

(3) ERCOT will provide verbal notice of an OCN to TOs and QSEs representing Resources through the TO and QSE Hotlines and post the message electronically to the ERCOT website. When an OCN is issued, it does not place ERCOT in an Emergency Condition. QSEs should notify, as appropriate, their represented QSEs, Resources, Retail Electric Providers (REPs) and Load Serving Entities (LSEs) of OCNs. TOs should notify, as appropriate, their represented Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs) of OCNs.

[NOGRR177: Replace paragraph (3) above with the following upon system implementation of NPRR857:]

(3) ERCOT will provide verbal notice of an OCN to TOs and QSEs representing Resources through the TO and QSE Hotlines and post the message electronically to the ERCOT website. When an OCN is issued, it does not place ERCOT in an Emergency Condition. QSEs should notify, as appropriate, their represented QSEs, Resources, Retail Electric Providers (REPs) and Load Serving Entities (LSEs) of OCNs. TOs should notify, as appropriate, their represented Transmission Service Providers (TSPs), Distribution Service Providers (DSPs) and Direct Current Tie Operators (DCTOs) of OCNs.

4.2.2 Advisory

(1) An Advisory will be issued by ERCOT in accordance with Protocol Section 6.5.9.3.2, Advisory, when it recognizes that conditions are developing or have changed such that QSE and/or TO actions may be prudent in anticipation of possible Emergency Conditions.

(2) ERCOT may require information from QSEs and TOs. Typical information requested may include, but is not limited to:

(a) Resource fuel capabilities;

(b) Resource condition details; and

(c) Actual weather conditions.

(3) ERCOT shall provide verbal notice of an Advisory to TOs and QSEs representing Resources through the TO and QSE Hotlines and shall post the message electronically to the ERCOT website. When an Advisory is issued, it does not place ERCOT in an Emergency Condition. QSEs shall notify, as appropriate, their represented QSEs, Resources, REPs and LSEs of Advisories. TOs should notify, as appropriate, their represented TSPs and DSPs of Advisories.

[NOGRR177: Replace paragraph (3) above with the following upon system implementation of NPRR857:]

(3) ERCOT shall provide verbal notice of an Advisory to TOs and QSEs representing Resources through the TO and QSE Hotlines and shall post the message electronically to the ERCOT website. When an Advisory is issued, it does not place ERCOT in an Emergency Condition. QSEs shall notify, as appropriate, their represented QSEs, Resources, REPs, and LSEs of Advisories. TOs should notify, as appropriate, their represented TSPs, DSPs and/or DCTOs of Advisories.

4.2.3 Watch

(1) A Watch may be issued by ERCOT in accordance with Protocol Section 6.5.9.3.3, Watch, when it recognizes that conditions have developed such that an Emergency Condition may be imminent.

(2) ERCOT may require information from QSEs and TOs. Typical information requested may include, but is not limited to:

(a) Resource fuel capabilities;

(b) Resource condition details; and

(c) Actual weather conditions.

(3) When a post-contingency overload of an element cannot be rectified, including through the use of CMPs, ERCOT shall issue a Watch.

(4) ERCOT shall provide verbal notice of the Watch to TOs and QSEs representing Resources through the TO and QSE Hotlines and shall post the message electronically to the ERCOT website. When a Watch is issued, it does not place ERCOT in an Emergency Condition. QSEs shall notify, as appropriate, their represented QSEs, Resources, REPs and LSEs of Watches. TOs shall notify, as appropriate, their represented TSPs and DSPs of Watches.

[NOGRR177: Replace paragraph (4) above with the following upon system implementation of NPRR857:]

(4) ERCOT shall provide verbal notice of the Watch to TOs and QSEs representing Resources through the TO and QSE Hotlines and shall post the message electronically to the ERCOT website. When a Watch is issued, it does not place ERCOT in an Emergency Condition. QSEs shall notify, as appropriate, their represented QSEs, Resources, REPs, and LSEs of Watches. TOs shall notify, as appropriate, their represented TSPs, DSPs and/or DCTOs of Watches.

4.2.4 Emergency Notice

(1) An Emergency Notice will be issued by ERCOT in accordance with Protocol Section 6.5.9.3.4, Emergency Notice, when ERCOT is operating in an Emergency Condition. This includes when ERCOT is considered to be in an insecure state when ERCOT Transmission Grid status is such that a Credible Single Contingency event presents the threat of uncontrolled separation of cascading Outages and/or large-scale service disruption to Load (other than Load being served from a single-feed transmission service) and/or overload of a Transmission Facility, and no timely solution is obtainable from the market.

(2) ERCOT shall provide verbal notice of an Emergency Notice to TOs and QSEs representing Resources through the TO and QSE Hotlines and shall post the message electronically to the ERCOT website.

(3) When an Emergency Notice is issued, ERCOT is operating in an Emergency Condition. QSEs shall notify their represented QSEs, Resources, REPs and LSEs as appropriate of Emergency Notices. TOs shall notify their represented TSPs, DSPs and LSEs as appropriate of Emergency Notices.

[NOGRR177: Replace paragraph (3) above with the following upon system implementation of NPRR857:]

(3) When an Emergency Notice is issued, ERCOT is operating in an Emergency Condition. QSEs shall notify, as appropriate, their represented QSEs, Resources, REPs and LSEs of Emergency Notices. TOs shall notify, as appropriate, their represented TSPs, DSPs, DCTOs, and LSEs of Emergency Notices.

4.3 Operation to Maintain Transmission System Security

(1) ERCOT shall continue to operate according to Security Criteria outlined in Section 2.2.2, Security Criteria, unless an Emergency Condition has been declared by ERCOT.

(2) Transmission Overload – ERCOT can:

(a) Order adjustment to unit generation schedules, switching of Transmission Elements or Load interruption to relieve the overloaded Transmission Element;

(b) Order a Transmission Element whose loss would not have a significant impact on the reliability of transmission system switched out to increase interconnected system transfers.

(3) Violation of security criteria – ERCOT can order changes to unit dispatch or commitment to eliminate or avoid a security criteria violation. Normally these changes should be performed through market control mechanisms including Security-Constrained Economic Dispatch (SCED) or Reliability Unit Commitment (RUC) as described in the Protocols, but if an ERCOT Operator finds these mechanisms insufficient to resolve the violation, the ERCOT Operator may require any other action necessary to address the violation.

(4) Partial Blackout or Blackout – ERCOT shall implement Black Start procedures.

4.3.1 Real-Time and Short Term Planning

(1) ERCOT will conduct Real-Time and short term planning based on the security criteria established in these Operating Guides. Operations during Forced and Planned Outages will also follow these criteria. Line Ratings are provided to ERCOT in accordance with Protocols and these Operating Guides. ERCOT will employ Constraint Management Plans (CMPs) and use of Remedial Action Schemes (RASs) to facilitate the use of the ERCOT Transmission Grid while maintaining system security and reliability in accordance with the Protocols, these Operating Guides, and applicable North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT will address operating conditions under which the reliability of the ERCOT System is inadequate and no solution is readily apparent in accordance with the Protocols and these Operating Guides.

4.4 Block Load Transfers between ERCOT and Non-ERCOT System

(1) Under Watch, Energy Emergency Alert (EEA) conditions, or for local transmission constraints, it may become necessary to implement Block Load Transfer (BLT) schemes which will transfer Loads normally located in ERCOT to a non-ERCOT System. Similarly, when a non-ERCOT System experiences certain transmission contingency or short supply conditions, ERCOT may be requested to transfer Loads normally located in the non-ERCOT System to ERCOT. All BLTs must comply with Protocol Section 6.5.9.5, Block Load Transfers between ERCOT and Non-ERCOT Control Areas.

4.5 Energy Emergency Alert (EEA)

4.5.1 General

(1) At times it may be necessary to reduce ERCOT System demand because of a temporary decrease in available electricity supply. The reduction in supply could be caused by emergency Outages of generators, transmission equipment, or other critical facilities; by short-term unavailability of fuel or generation; or by requirements or orders of

government agencies. To provide an orderly, predetermined procedures for curtailing Demand during such emergencies, ERCOT shall initiate and coordinate the implementation of the Energy Emergency Alert (EEA) in accordance with Protocol Section 6.5.9.4, Energy Emergency Alert.

(2) The goal of the EEA is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT System to reduce the chance of cascading outages.

4.5.2 Operating Procedures

(1) The ERCOT System Operators have the authority to make and carry through decisions that are required to operate the ERCOT System during emergency or adverse conditions. ERCOT will have sufficiently detailed operating procedures for emergency or short supply situations and for restoration of service in the event of a Partial Blackout or Blackout. These procedures will be distributed to the personnel responsible for performing specified tasks to handle emergencies, remedy short supply situations, or restore service. Transmission Service Providers (TSPs) will develop procedures to be filed with ERCOT describing implementation of ERCOT requests in emergency and short supply situations, including interrupting Load, notifying others and restoration of service.

[NOGRR177: Replace paragraph (1) above with the following upon system implementation of NPRR857:]

(1) The ERCOT System Operators have the authority to make and carry through decisions that are required to operate the ERCOT System during emergency or adverse conditions. ERCOT will have sufficiently detailed operating procedures for emergency or short supply situations and for restoration of service in the event of a Partial Blackout or Blackout. These procedures will be distributed to the personnel responsible for performing specified tasks to handle emergencies, remedy short supply situations, or restore service. Transmission Service Providers (TSPs) and Direct Current Tie Operators (DCTOs) will develop procedures to be filed with ERCOT describing implementation of ERCOT requests in emergency and short supply situations, including interrupting Load, notifying others and restoration of service.

(2) ERCOT and each TSP will endeavor to maintain transmission ties intact if at all possible. This will:

(a) Permit rendering the maximum assistance to an area experiencing a deficiency in generation;

(b) Minimize the possibility of cascading loss to other parts of the system; and

(c) Assist in restoring operation to normal.

[NOGRR177: Replace paragraph (2) above with the following upon system implementation of NPRR857:]

(2) ERCOT and Transmission Operators (TOs) will endeavor to maintain transmission ties intact if at all possible. This will:

(a) Permit rendering the maximum assistance to an area experiencing a deficiency in generation;

(b) Minimize the possibility of cascading loss to other parts of the system; and

(c) Assist in restoring operation to normal.

(3) ERCOT's operating procedures will meet the following goals while continuing to respect the confidentiality of market sensitive data. If all goals cannot be respected simultaneously then the priority order listed below shall be respected:

(a) Maintain station service for nuclear generating facilities;

(b) Securing startup power for power generating plants;

(c) Operating generating plants isolated from ERCOT without communication;

(d) Restoration of service to critical Loads such as:

(i) Military facilities;

(ii) Facilities necessary to restore the electric utility system;

(iii) Law enforcement organizations and facilities affecting public health; and

(iv) Communication facilities.

(e) Maximum utilization of ERCOT System capability;

(f) Utilization of Ancillary Services to the extent permitted by ERCOT System conditions;

(g) Utilization of the market to the fullest extent practicable without jeopardizing the reliability of the ERCOT System;

(h) Restoration of service to all Customers following major system disturbances, giving priority to the larger group of Customers; and

(i) Management of Interconnection Reliability Operating Limits (IROLs) shall not change.

4.5.3 Implementation

(1) ERCOT shall be responsible for monitoring system conditions, initiating the EEA levels below, notifying all Qualified Scheduling Entities (QSEs) representing Resources and Transmission Operators (TOs), and coordinating the implementation of the EEA conditions while maintaining transmission security limits. QSEs and TOs will notify all the Market Participants they represent of each declared EEA level.

(2) During the EEA, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using Direct Current Tie(s) (DC Tie(s)) or by using Block Load Transfers (BLTs) to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with North American Electric Reliability Corporation (NERC) scheduling guidelines.

(3) ERCOT, at management's discretion, may at any time issue an ERCOT-wide appeal through the public news media for voluntary energy conservation.

(4) There may be insufficient time to implement all levels in sequence. ERCOT may immediately implement EEA Level 2 when clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT may immediately implement Level 3 of the EEA any time the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes or when steady-state frequency falls below 59.8 Hz for any duration of time. ERCOT shall immediately implement Level 3 any time the steady-state frequency is below 59.5 Hz for any duration.

(5) Percentages for Level 3 Load shedding will be based on the previous year's TSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually.

(6) The ERCOT System Operator shall declare the EEA levels to be taken by QSEs and TSPs. QSEs and TSPs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or his designate, shall report back to the ERCOT System Operator when the requested level has been completed.

[NOGRR177: Replace paragraph (6) above with the following upon system implementation of NPRR857:]

(6) The ERCOT System Operator shall declare the EEA levels to be taken by QSEs, TSPs, and DCTOs. QSEs, TSPs, and DCTOs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or his designate, shall report back to the ERCOT System Operator when the requested level

has been completed.

(7) During EEA Level 3, ERCOT must be capable of manually shedding sufficient firm Load to arrest frequency decay and to prevent tripping of generators. The amount of manual firm Load to be shed may vary depending on ERCOT Transmission Grid conditions during the event. Each TSP will be capable of manually shedding its allocation of firm Load, without delay. The maximum time for the TSP to interrupt firm Load will depend on how much Load is to be shed and whether the Load is to be interrupted by Supervisory Control and Data Acquisition (SCADA) or other, non-SCADA-controlled methods. Since the need for firm Load shed is immediate, interruption by SCADA is preferred. Each TO, TSP, and Transmission and/or Distribution Service Provider (TDSP) and their designated agents will comply with the following requirements when implementing an ERCOT instruction to shed firm Load:

(a) Load interrupted manually by SCADA will be shed without delay upon receipt of a Load shed instruction and in a time period not to exceed 30 minutes after receipt of the Load shed instruction for each Entity's portion of every Load shed instruction. SCADA-controlled Load shed is preferred to be utilized by the TO and/or TDSP(s) before non-SCADA-controlled Load shed when executing a Load shed instruction;

(b) If sufficient amounts of SCADA-controlled Load are not available to fulfill an Entity's manual Load shed instruction, the TO and/or TDSP(s) shall complete, if applicable, the remaining manual Load shed through non-SCADA-controlled Load shed methods without delay upon receipt of a Load shed instruction and in a time period not to exceed one hour after receipt of the Load shed instruction. A TO shall notify ERCOT if its SCADA-controlled Load shed capabilities have been exhausted; and

(c) If determined appropriate by the TO and as soon as practicable, the TO and/or TDSP(s) should restore SCADA-controlled Load by shedding non-SCADA-controlled Load not shed in paragraph (b) above, in an effort to make SCADA-controlled Load available for a potential subsequent Load shed instruction.

(8) Each TSP, or its designated agent, will provide ERCOT a status report of Load shed progress within 30 minutes of the time of ERCOT's instruction or upon ERCOT's request.

(9) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(a) of Section 4.5.3.1, General Procedures Prior to EEA Operations, ERCOT may control the post-contingency flow to within the 15-Minute Rating in Security-Constrained Economic Dispatch (SCED). After Physical Responsive Capability (PRC) is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low, ERCOT shall restore control to the post-contingency flow to within the Emergency Rating for these constraints that utilized the 15-Minute Rating in SCED.

(10) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(b) of Section 4.5.3.1, ERCOT shall continue to enforce constraints associated with double-circuit contingencies throughout an EEA if the double-circuit failures are determined to be at high risk of occurring, due to system conditions. For all other double-circuit contingencies identified in paragraph (3)(b) of Section 4.5.3.1, ERCOT will enforce only the associated single-circuit contingencies during EEA Level 2 or 3. ERCOT shall resume enforcing such constraints as a double-circuit contingency after PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low. For constraints related to stability limits that are not IROLs, ERCOT may elect not to enforce double-circuit contingencies during EEA Level 3 only.

4.5.3.1 General Procedures Prior to EEA Operations

(1) Prior to declaring EEA Level 1 detailed in Section 4.5.3.3, EEA Levels, ERCOT may perform the following operations consistent with Good Utility Practice:

(a) Provide Dispatch Instructions to QSEs for specific Resources to operate at an Emergency Base Point to maximize Resource deployment so as to increase Responsive Reserve (RRS) levels on other Resources;

(b) Commit specific available Resources as necessary that can respond in the timeframe of the emergency. Such commitments will be settled using the Hourly Reliability Unit Commitment (HRUC) process;

(c) Start Reliability Must-Run (RMR) Units available in the time frame of the emergency. RMR Units should be loaded to full capability;

(d) Utilize available Resources providing RRS, ERCOT Contingency Reserve Service (ECRS), and Non-Spinning Reserve (Non-Spin) services as required;

(e) Instruct TSPs and Distribution Service Providers (DSPs) or their agents to reduce Customer Load by using existing, in-service distribution voltage reduction measures if ERCOT determines that the implementation of these measures could help avoid entering into EEA and ERCOT does not expect to need to use these measures to reduce the amount of Load shedding that may be needed in EEA Level 3. A TSP, DSP, or their agent shall implement these instructions if distribution voltage reduction measures are available and already installed. If the TSP, DSP, or their agent determines in their sole discretion that the distribution voltage reduction would adversely affect reliability, the voltage reduction measure may be reduced, modified, or otherwise changed from maximum performance to a level of exercise that has no negative impact to reliability; and

(f) ERCOT shall use the PRC and system frequency to determine the appropriate Emergency Notice and EEA levels.

[NOGRR265: Insert paragraph (2) below upon system implementation of NPRR1238 and renumber accordingly:]

(2) When PRC falls below 3,100 MW and is not projected to be recovered above 3,100 MW within 30 minutes following the deployment of Non-Spin, ERCOT may deploy some or all Voluntary Early Curtailment Loads (VECLs) via an Extensible Markup Language (XML) message, as described in Section 4.5.3.4, Qualified Scheduling Entity VECL Load Reduction Obligation, in order to maintain or restore 3,100 MW of PRC to the greatest extent possible.

(a) VECLs may be deployed and at any time in a Settlement Interval at the discretion of ERCOT operators.

(b) Upon deployment of any amount of VECLs, ERCOT shall notify all Market Participants via an operations message that such deployment has been made and shall specify the MW capacity of VECL deployed.

(c) ERCOT shall notify QSEs of the VECLs deployment via an XML message. The deployment time within the ERCOT XML deployment message shall initiate the VECL deployment and the VECL ramp period.

(d) Upon receipt of a VECL deployment, QSEs shall instruct their VECLs to reduce consumption without delay in a time period not to exceed 30 minutes from the start of the VECL ramp period, and the deployed VECLs shall comply with those instructions.

(e) If a VECL fails to comply with a deployment instruction, ERCOT may instruct the applicable TO to remotely disconnect the VECL. If a VECL that fails to comply with a deployment instruction is co-located with an ERCOT Resource, ERCOT may instruct the Customer's QSE to remotely disconnect the VECL, in which case the QSE shall ensure that the VECL is promptly disconnected from the ERCOT System.

(f) ERCOT shall notify QSEs of the termination of the VECLs deployment via an XML recall message. The ERCOT XML recall message shall represent the official notice of the VECLs recall.

(i) If ERCOT has instructed the interconnecting TO to disconnect a VECL for failure to comply with a deployment instruction, ERCOT will also notify the TO once the VECL deployment has been terminated, so that the VECL can be reconnected.

(g) Upon termination of the VECLs deployment, any VECL shall not increase consumption at a rate exceeding 20% per minute.

(h) Upon termination of VECLs deployment, ERCOT shall notify all Market Participants via an operations message that such deployment has been terminated and shall specify the MW capacity of VECLs recalled.

(2) When PRC falls below 3,000 MW and is not projected to be recovered above 3,000 MW within 30 minutes following the deployment of Non-Spin, ERCOT may deploy available contracted Emergency Response Service (ERS)-10 and ERS-30 via an Extensible Markup Language (XML) message. The deployment time within the ERCOT XML deployment message shall represent the beginning of the ERS-10 and ERS-30 ramp periods.

(a) ERS-10 and ERS-30 may be deployed at any time in a Settlement Interval. ERS-10 and ERS-30 may be deployed either simultaneously or separately, and in any order, at the discretion of ERCOT operators.

(b) Upon deployment, QSEs shall instruct their ERS Resources in ERS-10 and ERS-30 to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, until either ERCOT recalls the ERS-10 and ERS-30 deployment or the ERS-10 and ERS-30 Resources have reached their maximum deployment time.

(c) ERCOT shall notify QSEs of the recall of ERS-10 and ERS-30 via an XML message. The recall time within the ERCOT XML message shall represent the official notice of ERS-10 and ERS-30 recall.

(d) Upon recall, an ERS Resource shall return to a condition such that it is capable of meeting its ERS performance requirements as soon as practical, but no later than ten hours following the recall.

[NOGRR265: Replace paragraph (2) above with the following upon system implementation of NPRR1238:]

(3) When PRC falls below 3,000 MW and is not projected to be recovered above 3,000 MW within 30 minutes following the deployment of Non-Spin and all VECL, ERCOT may deploy available contracted Emergency Response Service (ERS)-10 and ERS-30 via an XML message. The deployment time within the ERCOT XML deployment message shall represent the beginning of the ERS-10 and ERS-30 ramp periods.

(a) ERS-10 and ERS-30 may be deployed at any time in a Settlement Interval. ERS-10 and ERS-30 may be deployed either simultaneously or separately, and in any order, at the discretion of ERCOT operators.

(b) Upon deployment, QSEs shall instruct their ERS Resources in ERS-10 and ERS-30 to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, until either ERCOT recalls the ERS-10 and ERS-30 deployment or the ERS-10 and ERS-30 Resources have reached their maximum deployment time.

(c) ERCOT shall notify QSEs of the recall of ERS-10 and ERS-30 via an XML message. The recall time within the ERCOT XML message shall represent the official notice of ERS-10 and ERS-30 recall.

(d) Upon recall, an ERS Resource shall return to a condition such that it is capable of meeting its ERS performance requirements as soon as practical, but no later than ten hours following the recall.

(3) When a Watch is issued for PRC below 3,000 MW and ERCOT expects system conditions to deteriorate to the extent that an EEA Level 2 or 3 may be experienced, ERCOT shall evaluate constraints active in SCED and determine which constraints have the potential to limit generation output.

(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:

[NOGRR177: Replace paragraph (a) above with the following upon system implementation of NPRR857:]

(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs and DCTOs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:

(i) A 15-Minute Rating is available that allows for additional transmission capacity for use in congestion management, if an EEA Level 2 or 3 is declared, and post-contingency actions can be taken within 15 minutes to return the flow to within the Emergency Rating. Such actions may include, but are not limited to, reducing the generation that increased output as a result of enforcing the 15-Minute Rating rather than the Emergency Rating;

(ii) Post-contingency loading of the Transmission Facilities is expected to be at or below Normal Rating within two hours; or

(iii) Additional transmission capacity could allow for additional output from a limited Generation Resource by taking one of the following actions:

(A) Restoring Transmission Elements that are out of service;

(B) Reconfiguring the transmission system; or

(C) Making adjustments to phase angle regulator tap positions.

If ERCOT determines that one of the above-mentioned actions allows for additional output from a limited Generation Resource, ERCOT may instruct the TSPs to take the action(s) during the Advisory to allow for additional output from the limited Generation Resource.

(b) ERCOT shall also coordinate with TSPs who own and operate the Transmission Facilities associated with the double-circuit contingencies for the constraints identified above to determine whether the double-circuit failures are at a high risk of occurring due to system conditions, which may include: severe weather conditions forecasted by ERCOT in the vicinity of the double-circuit, weather conditions that indicate a high risk of insulator flashover on the double-circuit, repeated Forced Outages of the individual circuits that are part of the double-circuit in the preceding 48 hours, or fire in progress in the right of way of the double-circuit.

[NOGRR177: Replace paragraph (b) above with the following upon system implementation of NPRR857:]

(b) ERCOT shall also coordinate with TSPs and DCTOs who own and operate the Transmission Facilities associated with the double-circuit contingencies for the constraints identified above to determine whether the double-circuit failures are at a high risk of occurring due to system conditions, which may include: severe weather conditions forecasted by ERCOT in the vicinity of the double-circuit, weather conditions that indicate a high risk of insulator flashover on the double-circuit, repeated Forced Outages of the individual circuits that are part of the double-circuit in the preceding 48 hours, or fire in progress in the right of way of the double-circuit.

(c) The actions detailed in this Section shall be supplemental to the development and maintenance of Constraint Management Plans (CMPs) as otherwise directed by the Protocols or Operating Guides.

(4) When a Watch is issued for PRC below 3,000 MW, QSEs shall suspend any ongoing ERCOT-required Resource performance testing.

4.5.3.2 General Procedures During EEA Operations

(1) ERCOT Control Area authority will re-emphasize the following operational practices during EEA operations to minimize non-performance issues that may result from the pressures of the emergency situation.

(a) ERCOT shall suspend Ancillary Service obligations that it deems to be contrary to reliability needs;

(b) ERCOT shall notify each QSE representing Resources and TO via ERCOT QSE and TO Hotlines of each declared EEA level and shall post the declared EEA level electronically to the ERCOT website;

(c) QSEs and TOs shall notify each represented Market Participant of declared EEA level;

(d) ERCOT, QSEs and TSPs shall continue to respect confidential market sensitive data;

[NOGRR177: Replace paragraph (d) above with the following upon system implementation of NPRR857:]

(d) ERCOT, QSEs, TSPs, and DCTOs shall continue to respect confidential market sensitive data;

(e) QSEs shall update Current Operating Plans (COPs) to limit or remove capacity when unexpected start-up delays occur or when ramp limitations are encountered;

(f) QSEs shall report when On-Line or available capacity is at risk due to adverse circumstances;

(g) QSEs, TSPs, and all other Entities must not suspend efforts toward expeditious compliance with the applicable EEA level declared by ERCOT nor initiate any reversals of required actions without ERCOT authorization;

[NOGRR177: Replace paragraph (g) above with the following upon system implementation of NPRR857:]

(g) QSEs, TSPs, DCTOs, and all other Entities must not suspend efforts toward expeditious compliance with the applicable EEA level declared by ERCOT nor initiate any reversals of required actions without ERCOT authorization;

(h) ERCOT shall define procedures for determining the proper redistribution of reserves during EEA operations; and

(i) QSEs shall not remove an On-Line Generation Resource or Energy Storage Resource (ESR) without prior ERCOT authorization unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, QSEs shall immediately inform ERCOT of the need and reason for removing the On-Line Resource from service.

4.5.3.3 EEA Levels

(1) ERCOT will declare an EEA Level 1 when PRC falls below 2,500 MW and is not projected to be recovered above 2,500 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 1:

(a) ERCOT shall take the following steps to maintain steady state system frequency near 60 Hz and maintain PRC above 2,000 MW:

(i) Request available Generation Resources that can perform within the expected timeframe of the emergency to come On-Line by initiating manual HRUC or through Dispatch Instructions, and request available ESRs that can perform within the expected timeframe of the emergency to come On-Line through Dispatch Instructions;

(ii) Use available DC Tie import capacity that is not already being used;

(iii) Issue a Dispatch Instruction for Resources to remain On-Line which, before start of emergency, were scheduled to come Off-Line; and

(iv) Instruct QSEs to deploy undeployed ERS-10 and ERS-30; and

(v) At ERCOT's discretion, manually deploy, through Inter-Control Center Communications Protocol (ICCP), available RRS and ECRS capacity from Generation Resources having a Resource Status of ONSC and awarded RRS or ECRS.

(b) QSEs shall:

(i) Ensure COPs, telemetered status, and telemetered High Sustained Limits (HSLs), Normal Ramp Rates, Emergency Ramp Rates, and Ancillary Service capabilities are updated and reflect all Resource delays and limitations; and

(ii) Ensure that each of its ESRs suspends charging until the EEA is recalled, except under the following circumstances:

(A) The ESR has a current SCED Base Point Instruction, Load Frequency Control (LFC) Dispatch Instruction, or manual Dispatch Instruction to charge the ESR;

(B) The ESR is actively providing Primary Frequency Response; or

(C) The ESR is co-located behind a Point of Interconnection (POI) with onsite generation that is incapable of exporting additional power to the ERCOT System, in which case the ESR may continue to charge as long as maximum output to the ERCOT System is maintained.

[NOGRR229: Replace paragraph (ii) above upon system implementation of NPRR995:]

(ii) Ensure that each of its ESRs and Settlement Only Energy Storage Systems (SOESSs) suspends charging until the EEA is recalled, except under the following circumstances:

(A) The ESR has a current SCED Base Point Instruction, Load Frequency Control (LFC) Dispatch Instruction, or manual Dispatch Instruction to charge the ESR;

(B) The ESR or SOESS is actively providing Primary Frequency Response; or

(C) The ESR or SOESS is co-located behind a Point of Interconnection (POI) with onsite generation that is incapable of exporting additional power to the ERCOT System, in which case the ESR may continue to charge as long as maximum output to the ERCOT System is maintained.

(2) ERCOT may declare an EEA Level 2 when the clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT will declare an EEA Level 2 when PRC falls below 2,000 MW and is not projected to be recovered above 2,000 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 2:

(a) In addition to the measures associated with EEA Level 1, ERCOT shall take the following steps to maintain steady state system frequency at a minimum of 59.91 Hz and maintain PRC above 1,500 MW:

(i) Instruct TSPs and DSPs or their agents to reduce Customer Load by using existing, in-service distribution voltage reduction measures that have not already been implemented. A TSP, DSP or their agent shall implement these instructions if distribution voltage reduction measures are available and already installed. If the TSP, DSP, or their agent determines in their sole discretion that the distribution voltage reduction would adversely affect reliability, the voltage reduction measure may be reduced, modified, or otherwise changed from maximum performance to a level of exercise that has no negative impact to reliability.

(ii) Instruct TSPs and DSPs to implement any available Load management plans to reduce Customer Load.

(iii) Instruct QSEs to deploy ECRS or RRS (controlled by high-set under-frequency relays) supplied from Load Resources. ERCOT may deploy ECRS or RRS from Load Resources simultaneously or separately.

ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraph (iv) below.

(iv) Load Resources providing ECRS that are not controlled by high-set under-frequency relays shall be deployed prior to deployment of those that have armed under-frequency relays. ERCOT shall deploy ECRS and RRS capacity supplied by Load Resources (controlled by high-set under-frequency relays) in accordance with the following:

(A) Instruct QSEs to deploy ECRS that is supplied from Load Resources (controlled by high-set under-frequency relays) that are only providing ECRS and then instruct QSEs to deploy Load Resources (controlled by high-set under-frequency relays) providing ECRS and RRS. QSEs will be given some discretion to deploy additional Load Resources not designated for deployment if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. The deployment time within the ERCOT XML deployment message shall initiate the ten-minute deployment period;

(B) At the discretion of the ERCOT Operator, instruct QSEs to deploy RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt additional Load Resources that are only providing RRS. ERCOT shall issue notification of the deployment via XML message. The deployment time within the ERCOT XML deployment message shall initiate the ten-minute deployment period;

(C) The ERCOT Operator may deploy all Load Resources providing RRS and ECRS at the same time. ERCOT shall issue notification of the deployment via XML message. The deployment time within the ERCOT XML deployment message shall initiate the ten-minute deployment period; and

(D) ERCOT shall develop a Real-Time process for deploying Load Resources based on a random sampling of individual Load Resources. At ERCOT's discretion, ERCOT may deploy all Load Resources at any given time during EEA Level 2.

(v) Unless a media appeal is already in effect, ERCOT shall issue an appeal through the public news media for voluntary energy conservation; and

(vi) With the approval of the affected non-ERCOT Control Area, TSPs, DSPs, or their agents may implement transmission voltage level BLTs, which transfer Load from the ERCOT Control Area to non-ERCOT Control Areas in accordance with BLTs as defined in the Operating Guides.

(b) Confidentiality requirements regarding transmission operations and system capacity information will be lifted, as needed to restore reliability.

(3) ERCOT may declare an EEA Level 3 when the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes or when steady-state frequency falls below 59.8 Hz. ERCOT will declare an EEA Level 3 when PRC cannot be maintained above 1,500 MW or when the clock-minute average system frequency falls below 59.91 Hz for 25 consecutive minutes. Upon declaration of an EEA Level 3, ERCOT shall take any of the following measures as necessary to recover frequency or PRC to the minimum required levels:

(a) Instruct ESRs to suspend charging. For ESRs, ERCOT shall issue the suspension instruction via a SCED Base Point instruction, or, if otherwise necessary, via a manual Dispatch Instruction. An ESR shall suspend charging unless it is providing Primary Frequency Response, has received a charging instruction via SCED Base Point, or is carrying Regulation Down Service (Reg-Down) and has received a charging instruction from LFC. However, an ESR co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System may continue to charge as long as maximum output to the ERCOT System is maintained.

[NOGRR229: Replace paragraph (a) above upon system implementation NPRR995:]

(a) Instruct ESRs to suspend charging. For ESRs, the suspension instruction shall be issued via a SCED Base Point, or, if otherwise necessary, via a manual Dispatch Instruction. An ESR shall suspend charging unless it is providing Primary Frequency Response, has received a charging instruction via SCED Base Point, or is carrying Regulation Down Service (Reg-Down) and has received a charging instruction from LFC. An SOESS shall suspend charging unless it is providing Primary Frequency Response. However, an ESR or SOESS co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System may continue to charge as long as maximum output to the ERCOT System is maintained.

(b) Direct all TOs to shed firm Load, in 100 MW blocks, distributed as documented in these Operating Guides in order to maintain a steady state system frequency at a minimum of 59.91 Hz and to recover 1,500 MW of PRC within 30 minutes.

(i) TOs and TDSPs may:

(A) Manually shed Load connected to under-frequency relays and/or under-voltage relays pursuant to an ERCOT Load shed directive issued during EEA Level 3 so long as the TO has determined that system conditions warrant utilizing Load connected to under-frequency and/or under-voltage relays and each affected TO continues to comply with its Under-Frequency Load Shed (UFLS) obligation as described in Section 2.6.1, Automatic Firm Load Shedding, and its Load shed obligation as described in Section 4.5.3.4, Load Shed Obligation.

(B) Manually shed Load that is armed to deploy as part of the 58.5 Hz, 58.7 Hz, and anti-stall UFLS stages, such that the UFLS Load falls below the TO's 25% Load relief obligation, as described in Section 2.6.1, in order to meet ERCOT operating instructions for manual Load shed if all Load identified for manual Load shed and the Load identified in paragraph (A) above has been shed.

(c) Implement any appropriate measures associated with EEA Levels 1 and 2 that have not already been implemented.

[NOGRR265: Insert Section 4.5.3.4 below upon system implementation of NPRR1238 and renumber accordingly:]

4.5.3.4 Qualified Scheduling Entity VECL Load Reduction Obligation

(1) Each QSE representing one or more VECLs shall take and direct actions to ensure that ERCOT VECL deployment instructions are effectuated. Each VECL shall comply with any reasonable instruction given by its QSE to effectuate Load reduction obligations.

4.5.3.4 Load Shed Obligation

[NOGRR265: Replace the title for Section 4.5.3.4 above with the following upon system implementation of NPRR1238:]

4.5.3.5 Transmission Operator Load Shed Obligation

(1) Each TO shall take and direct actions to ensure that ERCOT Load shed instructions are effectuated. Each DSP shall comply with any reasonable instruction given by its TO to effectuate Load shed obligations.

(2) Load shed obligation percentages for ERCOT EEA Level 3 Load shedding will be determined by calculating each TO's Load as a percentage of the ERCOT System summer and winter peak 15 minute Demand interval. For the purposes of this paragraph, TO Load will be the amount of Load being served by all of the TDSPs that the TO represents. The calculations for summer and winter Load shed obligation percentage are as follows:

[NOGRR265: Replace paragraph (2) above with the following upon system implementation of

NPRR1238:]

(2) Load shed obligation percentages for ERCOT EEA Level 3 Load shedding will be determined by calculating each TO's Load as a percentage of the ERCOT System summer and winter peak 15 minute Demand interval. For the purposes of this paragraph, TO Load, with the exception of VECLs, will be the amount of Load being served by all of the Transmission and/or Distribution Service Providers (TDSPs) that the TO represents. The calculations for summer and winter Load shed obligation percentage are as follows:

(a) The calculated Load shed obligation percentage for the summer Season will be based on the single highest coincident ERCOT System peak 15 minute Demand interval for the summer months of June through September as reflected in the 4-Coincident Peak (4-CP) data submitted by ERCOT to the Public Utility Commission of Texas (PUCT) for that year. Anticipated revisions to the summer Load shed table shall be posted as described in paragraph (4) below no later than March 31st of each year based on data from the previous calendar year.

(b) The calculated Load shed obligation percentage for the winter Season will be based on the single highest coincident ERCOT System peak 15 minute Demand interval for the winter months of December through February as reflected at the time that ERCOT extracts the Load data for the winter Season from its settlement system. Anticipated revisions to the winter Load shed table shall be posted as described in paragraph (4) below no later than August 31st of each year based on data from December of the previous calendar year and January through February of the current year.

(3) The summer Load shed table will be used during a hot weather Load shed event and the winter Load shed table will be used during a cold weather Load shed event. ERCOT will determine, in its sole discretion, whether an EEA event will be treated as a hot weather or cold weather Load shed event based on the weather conditions. The summer and winter Load shed time periods will be published annually with the updated obligation tables in paragraph (2) above. In addition, if ERCOT issues an Operating Condition Notice (OCN), it will notify Market Participants which Load shed table would apply to the potential Load shed event. When ERCOT directs TOs to shed Load, it will specify which Load shed table applies for the Load shed event. ERCOT shall use the same Load shed table for the duration of a Load shed event.

(4) ERCOT shall maintain the Seasonal Load shed tables reflecting each TO's total Load shed obligation on the ERCOT website. The Load shed obligation percentages will be reviewed by ERCOT and revised as described above, or as otherwise deemed appropriate by ERCOT, to reflect any new or changed TO designation by a DSP. Adjustments to the Load shed obligations due to changes in TO designations will be performed using the same Load data upon which the table was based. Following ERCOT's Seasonal peak Load reviews or ERCOT's receipt of any new or changed TO designation, ERCOT shall post any anticipated revisions to the Load shed tables on the ERCOT website. ERCOT shall issue a Market Notice announcing the posting of the revisions at least ten days prior

to the effective date of the revisions or as soon as practicable if ERCOT determines there is a need to correct the Market Notice less than ten days before the effective date.

[NOGRR265: Replace paragraph (4) above with the following upon system implementation of NPRR1238:]

(4) ERCOT shall maintain the Seasonal Load shed tables reflecting each TO's total Load shed obligation on the ERCOT website. The Load shed obligation percentages will be reviewed by ERCOT and revised as described above, or as otherwise deemed appropriate by ERCOT, to reflect any new or changed TO designation by a DSP or changes in the VECL registration. Adjustments to the Load shed obligations due to changes in TO designations will be performed using the same Load data upon which the table was based. Following ERCOT's Seasonal peak Load reviews or ERCOT's receipt of any new or changed TO designation, ERCOT shall post any anticipated revisions to the Load shed tables on the ERCOT website. ERCOT shall issue a Market Notice announcing the posting of the revisions at least ten days prior to the effective date of the revisions or as soon as practicable if ERCOT determines there is a need to correct the Market Notice less than ten days before the effective date.

(5) Each TO shall coordinate with each TDSP it represents to:

(a) Minimize overlap of circuits that are designated for manual firm Load shed with circuits that serve designated critical loads; and

(b) Minimize overlap of circuits that are designated for manual firm Load shed with circuits that are utilized for UFLS and Under-Voltage Load Shed (UVLS).

4.5.3.5 EEA Termination

(1) ERCOT shall:

(a) Continue EEA until sufficient Resources are available to ERCOT to eliminate the shortfall and restore adequate reserves;

(b) Restore full reserve requirements (normally 2300 MW);

(c) Terminate the levels in reverse order, where practical;

(d) Notify each QSE and TO of EEA level change termination via QSE and TO Hotlines and post the level change or termination electronically to the ERCOT website; and

(e) Maintain a stable ERCOT System frequency when restoring Load.

(2) QSEs and TOs shall:

(a) Implement actions to terminate previous actions as EEA levels are released in accordance with these Operating Guides;

(b) Notify represented Market Participants of EEA levels changes;

(c) Report back to the ERCOT System Operator when each level is accomplished; and

(d) Loads will be restored when specifically authorized by the ERCOT.

4.6 Black Start Service

(1) This section provides general guidelines to be followed in the event of a Partial Blackout or Blackout of the ERCOT System. Timely implementation of a Black Start plan compiled in accordance with Section 8, Attachment E, Black Start Plan Template, should facilitate coordination between ERCOT, Qualified Scheduling Entities (QSEs) who represent Black Start Resources, Black Start Resources, and Transmission Operators (TOs) and ensure restoration of service to the ERCOT System at the earliest possible time. The Authorized Representative for Resource Entities that own contracted Black Start Resources will provide their QSE and ERCOT with a copy of the individual plant start-up procedures for coordination of their activities with those of the appropriate TO.

(2) Pre-established plans and procedures cannot foresee all the possible combinations of system problems that may occur after a major failure. It is the responsibility of ERCOT to restore the system to normal, applying the principles, strategies, and priorities outlined in the ERCOT Black Start Plan.

4.6.1 Principles

(1) In order to minimize the time required, ERCOT will develop the Black Start Plan to utilize the principles, strategies, and priorities outlined in this Guide. The ERCOT Black Start Plan shall be coordinated with local TO Black Start plans to provide a coordinated Black Start reference.

(2) Each contracted Black Start Resource and each QSE with contracted Black Start Resource(s) will have readily accessible and sufficiently detailed current operating procedures to assist in an orderly recovery.

(3) Mutual assistance and cooperation will be essential during the restoration. Deliberate, careful action by each QSE, TO, and Resource Entity is necessary to minimize the length of time required for restoration and to avoid the reoccurrence of a Partial Blackout or Blackout of the ERCOT System.

(4) Throughout the restoration, recovery will depend on ERCOT receiving an accurate assessment of system conditions and status from each QSE, TO, and Resource Entity throughout the restoration. Adequate and reliable communications must be available

within the ERCOT System. During Black Start recovery, communication restrictions may enable the sharing of market sensitive information that pertains to the restoration of the ERCOT System. This includes but is not limited to availability status and recovery activities.

4.6.2 Strategies

(1) In the event of a Partial Blackout or Blackout of the ERCOT System, immediate steps must be taken to return the interconnected network to normal as quickly as possible. For detailed Black Start information, refer to Section 8, Attachment A, Detailed Black Start Information.

(a) Each TO shall immediately initiate its portion of the ERCOT Black Start Plan and attempt to establish contact with ERCOT. If communications with ERCOT are unavailable the TO shall immediately establish communications with its interconnected Black Start Resource(s) and the Black Start Resource's QSE.

(b) Each QSE representing Black Start Resources shall initiate communications with its Black Start Resources and immediately notify ERCOT and the appropriate TO of their condition and status.

(c) Available Black Start Resources shall immediately start their isolation and startup procedures and attempt to establish communications with the local TO.

(d) As generating and transmission capabilities become available, systematic restoration of ERCOT Load with respect to priorities shall begin in accordance with the local TO Black Start plans, taking care to balance Load and generating capability while maintaining an acceptable frequency.

(e) Appropriate voltage levels and reactive control must be maintained during the restoration. Consideration should be given to connecting Islands at locations having communications, frequency control, voltage control, synchronization facilities, and adequate transmission capacity. ERCOT will coordinate the return to full Automatic Generation Control (AGC) in the interconnection.

4.6.3 Priorities

(1) Priorities for an ERCOT System Black Start recovery are listed below:

(a) Secure and/or stabilize generating units where necessary.

(b) Prepare Cranking Paths and Synchronization Corridors as necessary to support restoration.

(c) Assess ERCOT System condition, and available communication facilities.

(d) Restore and maintain communication facilities to the extent possible.

(e) Bring units with contracted Black Start capability On-Line.

(f) Provide service to critical facilities:

(i) Provide station service for nuclear generating facilities;

(ii) Provide critical power to as many Generation Resources as possible to prevent equipment damage;

(iii) Secure or provide startup power for Generation Resources that do not have Black Start capability; and

(iv) Supply station service to critical substations where necessary.

(g) Connect Islands at designated synchronization points taking care to avoid recurrence of a Partial Blackout or Blackout of the ERCOT System.

(h) Restore service to critical Loads such as:

(i) Military facilities;

(ii) Facilities necessary to restore the electric utility system, including fuel sources;

(iii) Law enforcement organizations and facilities affecting public health; and

(iv) Public communication facilities.

(i) Restore service to the remaining Customers. Attention should be given to restoring feeders with under-frequency relay protection.

4.6.4 Responsibilities

(1) ERCOT's responsibilities are as follows:

(a) Shall maintain a Black Start plan in accordance with North American Electric Reliability Corporation (NERC) Reliability Standards and no more than 30 days after revising the Black Start plan, shall notify the TOs of the revised Black Start plan and post the plan with an effective date on the Market Information System (MIS) Certified Area for TOs;

(b) Shall, no more than 30 days after receiving a TO's new or revised Black Start plan, notify the TO of ERCOT's approval or disapproval of the TO's new or revised Black Start plan and post the approved TO's new or revised Black Start plan with an effective date on the MIS Certified Area to specified Market Participants requested by the TO;

(c) Coordinate and approve Planned Outage schedules for contracted Black Start Resources;

(d) Train TOs, QSEs, and Resource Entities that represent Black Start Resources in the restoration of the ERCOT System. This training will cover the theory of restoration and the processes that will need to be implemented during a Partial Blackout or Blackout;

[NOGRR194: Replace paragraph (d) above with the following upon system implementation of NPRR857:]

(d) Train TOs, QSEs, Direct Current Tie Operators (DCTOs), and Resource Entities that represent Black Start Resources in the restoration of the ERCOT System. This training will cover the theory of restoration and the processes that will need to be implemented during a Partial Blackout or Blackout;

(e) Will review the plans and procedures for consistency and conformance with these Operating Guides and ensure that they are updated at least annually;

(f) ERCOT shall report to the Reliability and Operations Subcommittee (ROS) by April 1 of each year a plan for review and any testing activities of Black Start Resources;

(g) Shall verify that the number, size, and location of Black Start Resources are sufficient to meet the ERCOT Black Start Plan; and

(h) In the event of a Partial Blackout or Blackout of the ERCOT System, ERCOT shall:

(i) Maintain continuous surveillance of the status of the ERCOT System;

(ii) Act as a central information collection and dissemination point for the ERCOT Region;

(iii) Coordinate reconnection of transmission;

(iv) Direct assistance for QSEs who represent Black Start Resources, TOs, Resource Entities, and Market Participants;

(v) Direct the distribution of reserves; and

(vi) Coordinate the return of the ERCOT System to AGC.

(2) TOs' responsibilities are as follows:

(a) Shall review and submit their Black Start plans to ERCOT via secured webmail or encrypted data transfer:

(i) Annually by November 1 of each year, for the upcoming calendar year. Plans submitted before November 1 will be deemed to have been received on November 1 for ERCOT to initiate the approval process described in paragraph (1)(b) above; and

(ii) When the Black Start plan for the current year has changed.

The TO may request that ERCOT post the TO's new or revised Black Start plan on the MIS Certified Area for specified Market Participants. The TO will have the responsibility to notify specified Market Participants that the new or revised Black Start plan has been posted on the MIS Certified Area; and

(b) In event of a Partial Blackout or Blackout of the ERCOT System:

(i) Shall communicate with local Black Start Resources and the Black Start Resource's QSE;

(ii) Coordinate switching to next start Resources and local Load;

(iii) Shall implement its local Black Start plan;

(iv) Shall follow the direction of ERCOT on behalf of represented Transmission Service Providers (TSPs) and Distribution Service Providers (DSPs);

[NOGRR177: Replace paragraph (iv) above with the following upon system implementation of NPRR857:]

(iv) Shall follow the direction of ERCOT on behalf of represented Transmission Service Providers (TSPs), DCTOs, and Distribution Service Providers (DSPs);

(v) Shall act as the regional ERCOT representative in coordinating interconnection of Resources; and

(vi) Shall follow the direction of ERCOT for reconnection of Islands.

(3) QSEs' representing Black Start Resources responsibilities are as follows:

(a) Verify that associated QSE personnel are proficient in implementation and use of the appropriate procedures for use in the event of a Partial Blackout or Blackout; and

(b) In the event of a Partial Blackout or Blackout of the ERCOT System, QSEs representing Black Start Resources shall:

(i) Take immediate steps to initiate and maintain communications with its Black Start Resources;

(ii) Supply ERCOT and/or the local TO with information on the status of generation, fuel, transmission, and communication facilities;

(iii) Follow the direction of the local TO or ERCOT in regards to output of its Generation Resources; and

(iv) Provide available assistance as directed by ERCOT or the local TO.

(4) Black Start Resources' responsibilities are as follows:

(a) Verify that associated Resource personnel are proficient in the implementation and use of appropriate individual plant start-up procedures for use in the event of a Partial Blackout or Blackout; and

(b) In the event of a Partial Blackout or Blackout of the ERCOT System, Black Start Resources shall:

(i) Isolate the Black Start Resource from the ERCOT Transmission Grid;

(ii) Establish communications with the local TO who is the primary contact for the Black Start Resource;

(iii) Supply the local TO and QSE with information on the status of generation, fuel, transmission isolation, and communication facilities;

(iv) Follow the appropriate plant start-up procedures and request synchronization and auxiliary Load pickup from the TO; and

(v) Follow the direction of the local TO or ERCOT until such time as normal system operations resume. The Black Start Resource should follow the direction of the QSE instructed by the TO or ERCOT when necessary.

(5) Generation Resources that are not Black Start Resources have the following responsibilities in the event of a Partial Blackout or Blackout of the ERCOT System:

(a) Take immediate steps to initiate and maintain communications with its QSE; and

(b) Follow the direction of the local TO or ERCOT until such time as normal system operations resume. The Generation Resource should follow the direction of the QSE as instructed by the TO or ERCOT when necessary.

(6) Section 8, Attachment A, Detailed Black Start Information, and Section 8, Attachment E, Black Start Plan Template, provide a detailed and specific Black Start information guide. Interested parties should use this information for technical reference material, Black Start testing, development of Black Start plans, and training of personnel.

4.6.5 Black Start Emergency Back Up Communication Facilities Criteria

(1) All back-up communications systems shall meet the following minimum requirements:

(a) Be operational for 72 hours immediately following the start of a Blackout without external power from the ERCOT System;

(b) Provide direct voice communications between Black Start Resource and TO, TO and other appropriate TOs, and TO and ERCOT; and

(c) Maintain written procedures that address operator training and the testing of the communication system;

(2) TOs shall have a satellite phone that meets the minimum back up communication requirements as a back-up communication system and that is compatible with ERCOT's satellite phone.

4.7 Geomagnetic Disturbance Operating Plan

4.7.1 Monitoring and Dissemination of Space Weather Information

(1) ERCOT shall maintain procedures to receive Geomagnetic Disturbance (GMD) alerts and warnings issued by the National Oceanic and Atmospheric Administration (NOAA).

(2) ERCOT shall implement and maintain procedures to provide GMD alerts and warnings to Transmission Operators (TOs).

(3) Other forecasted and current space weather information is publicly available directly through the NOAA website.

4.7.2 Development and Submission of TO GMD Operating Procedures or Processes

(1) Each TO that operates transmission equipment that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV shall develop a GMD operating procedure or process to mitigate the effects of GMD events on the reliable operation of its system.

(2) Each TO GMD operating procedure or process shall be provided to ERCOT as soon as practicable but no later than November 25, 2014. Updates to the plan shall be provided to ERCOT by March 15 of each subsequent year.

(3) Each TO GMD operating procedure or process shall include:

(a) A procedure to receive GMD alerts and warnings from ERCOT;

(b) A description of operational actions the TO intends to take to mitigate the effects of a GMD event. This description shall include:

(i) The triggering event for each action;

(ii) A detailed explanation of each operational action;

(iii) A list of Entities with which the TO must coordinate, if any, including any actions requested of other Entities in the ERCOT Region in order to implement the TO's GMD operating procedure or process; and

(iv) The conditions under which each action would be terminated.

(c) A procedure for reporting to ERCOT any unusual operational information that could be the result of GMD, such as high reactive loading, MVAr or voltage swings, high geomagnetically induced current on monitored transformers or equipment malfunctions.

4.7.3 ERCOT's GMD Operating Plan and ERCOT Review of TO GMD Operating Procedures or Processes

(1) ERCOT shall develop a GMD operating plan and post it on the Market Information System (MIS) Certified Area for TOs.

(2) The ERCOT GMD operating plan shall coordinate the TO GMD operating procedures or processes. This coordination is intended to ensure the TO GMD operating procedures or processes are not in conflict with one another and is not intended to be a review of the technical aspects of the TO GMD operating procedures or processes.

(3) In preparing the ERCOT GMD operating plan, ERCOT shall identify and notify the relevant TOs of any conflicts between the different TO GMD operating procedures or processes and any unacceptable actions requested of ERCOT in the TO operating procedures or processes.

(a) ERCOT and the TOs shall coordinate development of any required modifications to the TO GMD operating procedures or processes necessary to resolve these conflicts or unacceptable actions.

(b) A TO shall make the resulting modifications to its GMD operating procedures or processes.

(4) The ERCOT GMD operating plan shall include:

(a) A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system; and

(b) Any operating actions required of ERCOT by the TO GMD operating procedures or processes and approved by ERCOT for inclusion in the ERCOT GMD operating plan.

4.8 Responsive Reserve Service and ERCOT Contingency Reserve Service During Scarcity Conditions

(1) This Section details how Responsive Reserve (RRS) service may be manually deployed during scarcity conditions, pursuant to Protocol Section 6.5.7.6.2.2, Deployment of Responsive Reserve (RRS). The existing measure of scarcity is Physical Responsive Capability (PRC). If PRC drops below 3,000 MW, and all available Non-Spinning Reserve (Non-Spin) has been deployed, this process may be used. Scarcity conditions may occur during the Peak Load Season when ERCOT System Load is above 60,000 MW. For all other months, they could occur when ERCOT System Load is above 50,000 MW.

(a) When HSL – (Gen + 5-minute load ramp) <= 2000 MW, ERCOT may deploy Load Resources that are not Controllable Load Resources (CLRs) and that are providing ERCOT Contingency Reserve Service (ECRS) or RRS.

4.8.1 Responsive Reserve Service and ERCOT Contingency Reserve Service Manual Recall

(1) The operator will consider system conditions and Ancillary Services in releasing or recalling RRS. System frequency, load ramp, and factors such as Regulation Up Service (Reg-Up) versus Regulation Down Service (Reg-Down) deployment status will be considered.

(2) The manual deployment of RRS or ECRS for capacity from Load Resources that are not CLRs may be recalled pursuant to Protocol Section 6.5.9, Emergency Operations.

ERCOT Nodal Operating Guides

Section 5: Network Operations Modeling Requirements

December 5, 2025

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5 NETWORK OPERATIONS MODELING REQUIREMENTS

5.1 System Modeling Information

(1) Information on existing and future ERCOT System components and topology is necessary for ERCOT to create databases and perform tests as outlined in these criteria. To ensure that such information is made available to ERCOT, the following actions by Market Participants are required:

(a) Each Transmission Service Provider (TSP), or its Designated Agent, shall provide accurate modeling information for all Transmission Facilities owned or planned by the TSP. The information provided shall include, but not be limited to, the following:

(i) Information necessary to represent the TSP's Transmission Facilities in any model of the ERCOT Transmission Grid whose creation has been approved by ERCOT, including modeling information detailed in procedures of the Steady State Working Group (SSWG), Dynamics Working Group (DWG), and System Protection Working Group (SPWG);

(ii) Identification of a designated contact person, generally regarded as the working group TSP representative, responsible for providing answers to questions ERCOT may have regarding the information provided; and

(iii) TSP owned or operated Transmission Facility data provided and used to accurately represent a Transmission Facility in a model shall be consistent to the extent practicable with data provided and used to represent that same Transmission Facility in any other model created to represent a time period during which the Transmission Facility is expected to be physically identical. All existing transmission lines' and transformers' impedances, or equivalent branch circuit impedance, and Ratings shall be identical, to the extent practicable. If all normally closed breakers and switches are closed and normally open breakers and switches are open in the Network Operations Model, the calculated line flows between substations in the Annual Planning Model shall be consistent, when all models use the same load magnitude and distribution, generation commitment and dispatch, and Voltage Profile.

(b) Each TSP, or its Designated Agent, owning or planning Transmission Facilities shall attend the scheduled meetings and otherwise participate in the activities of the SSWG, DWG, and the SPWG, unless specifically exempted from these activities by ERCOT.

(c) Each Generation Resource and Energy Storage Resource (ESR), or a Designated Agent for the Resource, shall provide accurate modeling information for each existing or proposed Resource meeting the criteria for inclusion in the SSWG, DWG, and SPWG base cases for which it is the majority owner. The information provided shall include, but not be limited to, the following:

(i) Information necessary to represent the Resource's generation and interconnection facilities in any model of the ERCOT System whose creation has been approved by ERCOT, including modeling information detailed in procedures of the SSWG, DWG, and SPWG; and

(ii) Identification of a designated contact person responsible for providing answers to questions ERCOT may have regarding the information provided.

[NOGRR177: Replace paragraph (c) above with the following upon system implementation of NPRR857:]

(c) Each Generation Resource, Energy Storage Resource (ESR), or Direct Current Tie Operator (DCTO), or a Designated Agent for the Resource or DCTO, shall provide accurate modeling information for each existing or proposed Resource or Transmission Facility meeting the criteria for inclusion in the SSWG, DWG, and SPWG base cases for which the Resource or DCTO is the majority owner. The information provided shall include, but not be limited to, the following:

(i) Information necessary to represent the Resource's generation and interconnection facilities and the DCTO's Transmission Facilities in any model of the ERCOT System whose creation has been approved by ERCOT, including modeling information detailed in procedures of the SSWG, DWG, and SPWG; and

(ii) Identification of a designated contact person responsible for providing answers to questions ERCOT may have regarding the information provided.

(d) Typical or representative information may be provided for planned facility additions or modifications for use in the SSWG, DWG, and SPWG base cases, but such information shall be revised using actual design or construction information in accordance with the time line for Network Operations Model changes outlined in Protocol Section 3.10.1, Time Line for Network Operations Model Changes.

(e) Congestion Revenue Right (CRR) Network Model Outage determination uses network topology of the CRR Network Model identified by ERCOT. This must include Outages of Transmission Elements with a status of approved or accepted by ERCOT at the time the CRR Network Model is being built and that demonstrate significant impact to the transfer capability during the effective period. ERCOT will consider including Outages in the CRR Network Model that are scheduled to occur in the relevant time period and meet one or more of the following criteria:

(i) Consecutive or continuous approved or accepted Outages greater than or equal to five days;

(ii) Approved or accepted Outages which include Transmission Elements included in the definition of a Hub;

(iii) Approved or accepted Outages which include Transmission Elements in a 345 kV Transmission Facility;

(iv) Approved or accepted Outages that require the use of a Block Load Transfer (BLT); and

(v) Any other approved or accepted Outage that has been determined by ERCOT to carry a substantial risk of causing significant congestion.

(f) As set forth in Protocol Section 7.5.1, Nature and Timing, all Outages included in the CRR Network Model shall be posted on the Market Information System (MIS) Secure Area consistent with the model posting requirements and with accompanying cause and duration information, as indicated in the Outage Scheduler.

ERCOT Nodal Operating Guides

Section 6: Disturbance Monitoring and System Protection

February 1, 2026

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6 DISTURBANCE MONITORING AND SYSTEM PROTECTION

6.1 Disturbance Monitoring Requirements

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

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

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

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

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

6.1.1 Introduction

(1) Disturbance monitoring is necessary to:

(a) Determine performance of the ERCOT System;

(b) Determine effectiveness of protective relaying systems;

(c) Verify ERCOT System models;

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

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

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

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

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

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

6.1.1.1 Applicability

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

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

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

6.1.2 Fault Recording and Sequence of Events Recording Equipment

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

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

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

6.1.2.1 Fault Recording Requirements

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

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

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

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

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

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

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

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

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

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

6.1.2.2 Fault Recording and Sequence of Events Recording Equipment Location Requirements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[NOGRR255: Replace paragraph (2) above with the following no earlier than August 1, 2026:]

(2) Facility owners shall have at least 50% of the new fault recording and sequence of events recording equipment identified in paragraph (1) above installed.

[NOGRR255: Delete paragraph (2) no earlier than August 1, 2028 and renumber accordingly.]

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

6.1.2.3 Fault Recording and Sequence of Events Recording Data Requirements

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

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

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

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

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

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

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

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

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

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

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

(a) Time stamp;

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

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

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

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

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

(g) Applicable binary status.

(4) If the fault recorder does not directly measure the values in paragraphs (3)(d) through (3)(f) above, then dynamic disturbance recording or phasor measurement unit data is acceptable so long as data of sufficient resolution is available to validate dynamic

models, identify protection system actions, and identify the cause of a ride-through failure.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6.1.3 Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment

(1) Phasor measurement recording equipment includes all dynamic disturbance recording equipment with phasor measurement recording capability that meets the requirements in Section 6.1.3.1.1, Recording and Triggering Requirements, and 6.1.3.1.3, Dynamic Disturbance Recording Data Recording and Redundancy Requirements. All new or replaced dynamic disturbance recording equipment installed after June 1, 2024 shall function as or provide phasor measurement unit(s) and meet requirements in Section 6.1.3.1.2, Dynamic Disturbance Recording Equipment Location Requirements. If an existing trigger based dynamic disturbance recording equipment fails to record and provide data more than one time in a rolling 36 month period, ERCOT may require it to be replaced with a phasor measurement recording capability that meets the requirements in Section 6.1.3.1.1 and 6.1.3.1.3. In such instances, ERCOT would notify the facility owner and the facility owner shall install the new equipment within 18 months.

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

6.1.3.1 Dynamic Disturbance Recording Equipment Requirements

6.1.3.1.1 Recording and Triggering Requirements

(1) Dynamic disturbance recording equipment shall:

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

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

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

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

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

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

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

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

(b) Record lengths of at least three minutes;

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

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

6.1.3.1.2 Dynamic Disturbance Recording Equipment Location Requirements

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

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

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

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

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

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

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

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

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

(a) One Transmission Element; and

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

6.1.3.1.3 Dynamic Disturbance Recording Data Recording and Redundancy Requirements

(1) Recorded electrical quantities shall determine the following:

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

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

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

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

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

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

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

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

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

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

6.1.3.1.4 Dynamic Disturbance Recording Data Retention and Data Reporting Requirements

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

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

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

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

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

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

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

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

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

6.1.3.2 Phasor Measurement Unit Requirements

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

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

6.1.3.2.1 Phasor Measurement Unit Recording Requirements

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

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

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

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

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

6.1.3.2.2 Phasor Measurement Unit Location Requirements

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

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

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

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

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

[NOGRR177: Insert item (e) below upon system implementation of NPRR857 and renumber accordingly:]

(e) New Direct Current Ties (DC Ties) placed into service after January 1, 2019;

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

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

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

(h) A Transmission Element within:

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

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

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

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

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

(i) ERCOT may require installation of phasor measurement recording equipment;

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

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

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

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

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

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

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

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

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

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

[NOGRR255: Replace paragraph (2) above with the following no earlier than August 1, 2026:]

(2) Transmission Facility owners and Generation Resource Facility owners shall have at least 50% of applicable new phasor measurement units identified in paragraph (1) above installed.

[NOGRR255: Delete paragraph (2) no earlier than August 1, 2028.]

6.1.3.2.3 Phasor Measurement Unit Data Recording and Redundancy Requirements

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

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

(i) Time stamp;

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

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

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

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

(i) Time stamp;

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

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

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

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

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

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

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

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

6.1.3.2.4 Phasor Measurement Unit Data Retention and Data Reporting Requirements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6.1.4.1 Fault Recording and Sequence of Events Recording Equipment Requirements

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

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

6.1.4.1.1 Sequence of Events Recording Data Requirements

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

6.1.4.1.2 Fault Recording Data and Triggering Requirements

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

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

(i) Time stamp;

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

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

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

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

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

(vii) Applicable binary status.

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

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

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

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

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

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

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

(2) Protective relay tripping for all protection groups;

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

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

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

(b) Minimum recording rate of:

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

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

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

6.1.4.3 Phasor Measurement Unit Equipment Requirements

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

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

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

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

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

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

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

(a) Time stamp;

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

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

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

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

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

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

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

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

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

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

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

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

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

(d) Fault recording and phasor measurement unit data in electronic files formatted in conformance with IEEE C37.111, IEEE Standard for COMTRADE, revision C37.111-1999 or later;

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

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

6.1.5 Maintenance and Testing Requirements

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

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

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

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

(a) Restore the recording capability, or

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

6.1.5.1 Geomagnetic Disturbance (GMD) Measurement Data Processes

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

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

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

6.1.6 Equipment Reporting Requirements

(1) Each Market Participant with dynamic disturbance recording, phasor measurement recording, fault recording, or sequence of events recording equipment identified by

Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment, Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment, and Section 6.1.4, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs), shall:

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

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

6.1.7 Review Process

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

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

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

6.2 System Protective Relaying

6.2.1 Introduction

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

(a) Protective relays which respond to electrical quantities;

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

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

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

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

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

6.2.1.1 Applicability

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

6.2.2 Design and Operating Requirements for ERCOT System Facilities

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

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

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

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

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

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

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

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

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

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

6.2.3 Performance Analysis Requirements for ERCOT System Facilities

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

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

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

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

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

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

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

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

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

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

(4) All Remedial Action Scheme (RAS) misoperations shall be documented, including corrective actions, and the documentation supplied to ERCOT, the Reliability Monitor, and the NERC Regional Entity, per the timeline established in paragraph (1) of Section

11.2.1, Reporting of RAS Operations. Any of the following events constitute a reportable RAS misoperation:

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

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

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

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

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

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

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

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

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

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

6.2.4 Protective Relay System Failure Response

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

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

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

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

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

(a) Removing the affected facility from service, and

(b) Entering the status change into Outage Scheduler.

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

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

(b) Possible reconfiguration of the ERCOT System; or

(c) Firm Load shed.

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

6.2.5 Maintenance and Testing Requirements for ERCOT System Facilities

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

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

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

6.2.6 Requirements and Recommendations for ERCOT System Facilities

6.2.6.1 General Protection Criteria

6.2.6.1.1 Dependability

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

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

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

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

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

6.2.6.1.2 Security

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

6.2.6.1.3 Dependability and Security

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

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

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

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

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

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

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

6.2.6.1.4 Operating Time

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

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

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

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

6.2.6.1.5 Testing and Maintenance

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

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

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

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

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

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

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

(f) Check that proper settings have been made;

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

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

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

6.2.6.1.6 Analysis of System Performance and Associated Protection Systems

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

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

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

(b) Fault recorder traces;

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

(d) Fault locator data;

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

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

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

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

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

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

(k) Manufacturers' application and design engineers.

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

(a) Gather data;

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

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

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

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

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

(g) Iterate;

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

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

6.2.6.2 Equipment and Design Considerations

6.2.6.2.1 Current Transformers

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

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

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

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

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

(6) Other considerations include:

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

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

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

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

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

6.2.6.2.2 Voltage Transformers and Potential Devices

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

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

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

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

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

(6) Other considerations include:

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

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

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

6.2.6.2.3 Batteries and Direct Current Supply

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

(2) Two batteries each with its own charger should be provided at each location. An acceptable alternative is one battery with two separately protected branches. The two protective relay systems protecting a zone shall be supplied from the separate batteries or branches. For transmission facilities at 100 kV and above, two batteries shall be required

in locations that remote backup clearing of lines and substation faults is not achieved. For new upgraded transmission facilities at 200 kV and above with two or more transmission voltage breakers, two batteries each with its own charger, are required.

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

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

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

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

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

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

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

6.2.6.2.4 AC Auxiliary Power

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

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

6.2.6.2.5 Circuit Breakers

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

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

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

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

6.2.6.2.6 Communications Channels

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

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

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

(4) Other considerations include:

(a) Report loss of channel over SCADA;

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

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

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

[NOGRR177: Replace paragraph (e) above with the following upon system implementation of NPRR857:]

(e) See also Section 7.1.2, WAN Participant Responsibilities.

6.2.6.2.7 Control Cables and Wiring

(1) Control cables, wiring and auxiliary control devices should be such as to assure high reliability with due consideration to published codes and standards, fire hazards, current-

carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

(2) Other considerations include:

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

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

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

(d) No splice in any wire or cable;

(e) All cables terminated on terminal blocks; and

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

6.2.6.2.8 Environment

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

(2) Other potential hazards detrimental to installations include:

(a) Fire ants;

(b) Snakes;

(c) Trash and leftover hardware;

(d) Gunfire;

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

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

(g) Rats;

(h) Dust, dirt, grime;

(i) Water;

(j) Theft of substation and transmission grounds; and

(k) Batteries located in same room as relays.

6.2.6.3 Specific Application Considerations

6.2.6.3.1 Transmission Line Protection

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

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

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

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

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

(3) Transmission line protection should include:

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

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

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

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

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

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

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

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

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

6.2.6.3.2 Transmission Station Protection

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

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

(3) Station protection should consist of:

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

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

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

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

6.2.6.3.3 Breaker Failure Protection

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

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

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

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

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

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

6.2.6.3.4 Generator and Energy Storage Resource Protection and Relay Requirements

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

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

(a) Unbalanced phase currents;

(b) Loss of excitation;

(c) Over-excitation;

(d) Field ground;

(e) Inadvertent energization or reverse power;

(f) Uncleared system faults; and

(g) Off-frequency.

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

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

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

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

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

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

6.2.6.3.5 Automatic Under-Frequency Load Shedding Protection Systems

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

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

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

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

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

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

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

6.2.6.3.6 Automatic Under-Voltage Load Shedding Protection Systems

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

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

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

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

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

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

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

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

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

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

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

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

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

ERCOT Nodal Operating Guides

Section 7: Telemetry and Communication

February 1, 2026

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7 Telemetry and Communication

7.1 ERCOT Wide Area Network

(1) ERCOT interfaces with Wide Area Network (WAN) Participants over the WAN. ERCOT is responsible for the design, configuration, maintenance, and management of the communications network infrastructure required to support WAN connectivity. This includes, but is not limited to, ERCOT issued routers, switches, and out-of-band management equipment. The ERCOT WAN is a redundant, highly available network providing connectivity to ERCOT sites and each Market Participant site. See Figure 1, ERCOT Wide Area Network Overview, in Section 7.1.2, WAN Participant Responsibilities.

(2) The primary purpose of the ERCOT WAN is to facilitate Transmission Control Protocol/Internet Protocol (TCP/IP) connectivity between ERCOT and WAN Participants for exchange of:

(a) Inter-Control Center Communications Protocol (ICCP) Data, including but not limited to Real-Time telemetry data for wholesale operations, frequency control, and transmission security; and

(b) Application Programming Interface (API) data, including but not limited to, Resource-Specific Extensible Markup Language (XML) Data, such as market operations, operating plans, Outage requests, or Dispatch instructions.

(3) The ERCOT WAN is also used to facilitate dedicated voice communication between ERCOT and Market Participants.

(4) Data exchanged between ERCOT and WAN Participants shall use the ERCOT WAN for the following types of data:

(a) ICCP Data;

(b) Resource-Specific XML Data; and

(c) Operational voice communications for both normal and emergency use. The ERCOT WAN includes support for, but not limited to, off-premise exchanges (OPX) with ERCOT's control facilities and the ERCOT Hotlines.

(5) ERCOT may approve conditional use of other forms of data exchange or communications for exchange of the types of data listed in paragraph (4) above when a WAN Participant loses their connection to the ERCOT WAN. A WAN Participant may use the Internet as a tertiary communication path if the ERCOT WAN and backup communication paths are both unavailable.

(6) WAN Participants shall sign the ERCOT Private WAN Agreement in the current form required by ERCOT as a condition to be granted access to the WAN.

(7) A Qualified Scheduling Entity (QSE) representing a Resource or a QSE representing an Emergency Response Service (ERS) Resource may designate another QSE (including a Data Agent-Only QSE, as provided in ERCOT Protocol Section 16.2.1.1, Data Agent-Only Qualified Scheduling Entities) as its agent for purposes of exchanging over the ERCOT WAN one or more of the types of data listed in paragraph (4) above. Such designation shall be made using the QSE Agency Agreement form.

(8) ERCOT shall provide encryption and manage the related encryption keys for data transmitted between ERCOT and each ERCOT-managed router at each WAN Participant's WAN demarcation point. QSEs and Transmission Operators (TOs) are responsible for providing security protection of data transmitted downstream from the ERCOT-managed router.

7.1.1 ERCOT Responsibilities

(1) ERCOT's responsibilities include the following:

(a) Supply Customer Premises equipment (i.e. equipment at WAN Participant facilities for the WAN) including routers, Local Area Network (LAN) switch/hub and all support equipment for management purposes;

(b) Order and provision of local loop, network access point and transport;

(c) Complete required coordinated WAN qualification testing and approval for service;

(d) Provide 24-hour network monitoring and management;

(e) Provide 24x7 maintenance, with 4-hour response, for all ERCOT equipment located at WAN Participant site; and

(f) The ERCOT Helpdesk will be the single point of contact for all network issues, and the ERCOT Helpdesk will provide periodic updates to the WAN Participant until the issue is resolved.

7.1.2 WAN Participant Responsibilities

(1) WAN Participant responsibilities include the following:

(a) A prospective WAN Participant is required to complete a WAN application, signed by the WAN Participant's Authorized Representative, and sign the ERCOT Private WAN Agreement, which governs installation, operation, and maintenance of the WAN hardware. Appropriate WAN documents can be obtained by contacting ERCOT. The WAN application shall include the following information at a minimum:

(i) WAN circuit termination location and requested functionality specifications;

(ii) WAN Participant's primary and backup contacts for WAN facilities management and services;

(iii) WAN Participant's primary and backup contacts for WAN emergency restoration;

(iv) WAN Invoicing contact information;

(v) WAN Participant's 24x7 operations desk long distance number; and

(vi) WAN Participant's 24x7 analog line for maintenance.

(b) Each WAN Participant must timely update information provided to ERCOT in the application process, and must promptly respond to any reasonable request by ERCOT for updated information regarding the WAN Participant or the information provided to ERCOT in paragraph (a) above. Changes to any of the information listed in paragraph (a) above shall be submitted to ERCOT using a Notice of Change of Information (NCI) form.

(c) A WAN Participant shall provide physical security systems compliant with the applicable Critical Infrastructure Protection (CIP) requirement of the North American Electric Reliability Corporation (NERC) Reliability Standards.

(d) WAN Participant equipment provided by ERCOT that exchanges ICCP Data, Resource-Specific XML Data, or operational voice communications with ERCOT shall connect directly to the ERCOT WAN. ERCOT will work with each WAN Participant to determine the most appropriate WAN demarcation point. Criteria for determining demarcation points include:

(i) Reliability;

(ii) Location of data centers;

(iii) Location of control centers and/or communication centers;

(iv) Location of disaster recovery facilities;

(v) Location of Energy and Market Management System (EMMS) equipment;

(vi) Location of ICCP equipment;

(vii) Location of Resource-Specific XML equipment; and

(viii) Location of private branch exchange (PBX) or call management equipment installation.

(e) ERCOT is responsible for designating necessary WAN equipment for the reliable transport of communications over the ERCOT WAN and will make the ultimate determination of the demarcation point location.

(f) A WAN Participant that serves both Transmission Service Provider (TSP) and QSE functions at one location may have a single ERCOT WAN connection as defined in Section 7.1, ERCOT Wide Area Network, at that location.

(g) If a TSP and QSE share a centralized PBX or call management, separate OPX circuits will be terminated for each participant.

(h) Each WAN Participant is required to extend the ERCOT OPX and Hotline voice circuits into its 24x7 operations desk. The OPX and Hotline voice circuits are transported across the ERCOT WAN. If a WAN Participant is designated to represent another Market Participant through an agency agreement approved by ERCOT, the WAN Participant must have dedicated OPX circuits for each Market Participant represented, in addition to a dedicated OPX for the WAN Participant if it is also representing Resources. In these cases, a single Hotline button will be used for the WAN Participant and all of the represented Market Participants. The Market Participant and its agent, if applicable, are both responsible for delivering the Hotline and the OPX to the Market Participant's 24x7 operations desk in a manner that reasonably assures continuous communication with ERCOT and is not affected by calling features such as automatic transfer or roll to voice mail. Also, a touchtone keypad is required for the Hotline to be able to provide an acknowledged receipt. The demarcation point for all voice circuits is the WAN Participant's router.

(i) Each WAN Participant must provide internal facilities and communications to collect and furnish data and voice signals to the ERCOT WAN as required by the Protocols. For TSPs and TOs such data includes, but is not limited to, voice communications, ICCP Data, and Supervisory Control and Data Acquisition (SCADA) for substations and other Transmission Facilities. For QSEs such data includes, but is not limited to, operational voice communications, ICCP Data, Resource-Specific XML Data, and SCADA for Resources.

(j) A WAN Participant shall provide adequate physical facilities to support the ERCOT WAN communications equipment. The physical facilities and communications equipment requirements include the following:

(i) Provide an analog business phone line or PBX analog extension for troubleshooting and maintenance of equipment;

(ii) Provide a height of 24" of rack space in a 19" wide rack;

(iii) Provide two separate uninterruptible power supply single-phase 115 VAC 20 amp circuits, each with four receptacles in the 19" rack listed above;

(iv) Provide building wiring from circuit termination to equipment rack;

(v) Within 24-hours notice, provide ERCOT employees or contractors access to the communication facility;

(vi) Within one-hour notice, provide ERCOT employees or contractors emergency access to the communication facility;

(vii) Provide onsite personnel to escort ERCOT employees or contractors;

(viii) Provide a firewall or router, located at the WAN Participant site, for the network address translation of internal WAN Participant addresses to external addresses on the ERCOT LAN;

(ix) Provide connectivity from WAN Participant firewall or router to ERCOT LAN located at WAN Participant site. WAN Participants are responsible for their own security through this connection;

(x) Dual cable entrances to WAN Participant, connecting to different Telco Central Offices are highly recommended; and

(xi) Provide ERCOT with internal IP addressing scheme as needed for network design. This will be kept confidential.

(k) A WAN Participant shall supply, implement, and maintain all data and voice communication facilities required to fulfill the obligations set forth in these Nodal Operating Guides.

(l) A WAN Participant's installation of data and voice communication facilities described in paragraph (k) above must complete qualification testing as specified by ERCOT before ERCOT will grant approval to commence operational use of the WAN connection. A WAN Participant shall request prior approval from ERCOT of any changes in data and voice communication facilities that impact connectivity through the WAN and shall coordinate with ERCOT before commencing operational use.

(m) If a WAN Participant extends its network or otherwise transmits WAN Data or operational voice communications to another of its control and/or data center or another WAN Participant's control and/or data center, then such communications shall be transmitted or received using a Secure Private Network (SPN).

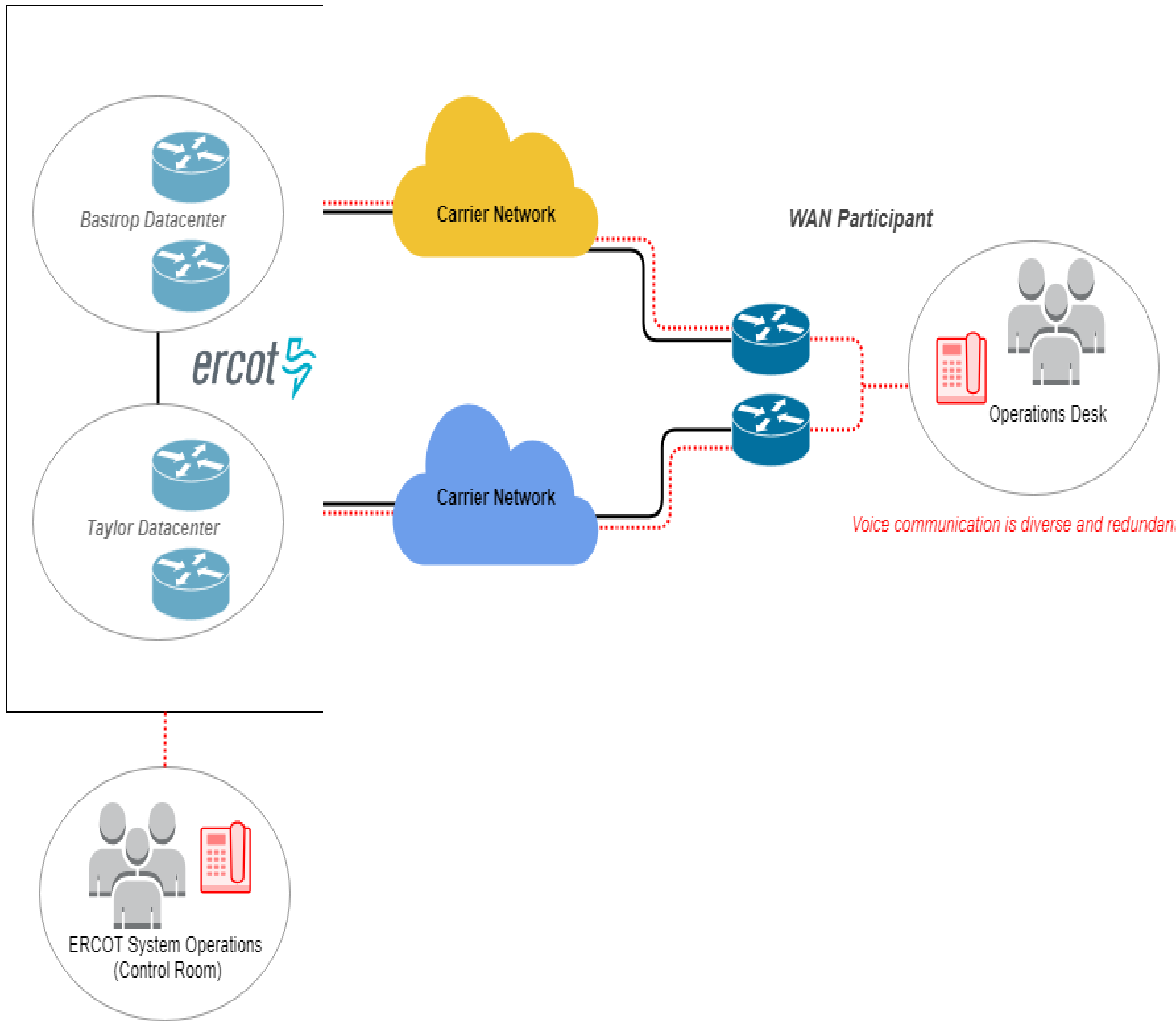

Figure 1: ERCOT Wide Area Network Overview

(n) If a WAN Participant is a QSE that represents a Resource Entity, ERS Resource, or another QSE for whom it receives or transmits WAN Data, the WAN Participant shall utilize an SPN or other network that provides equivalent protection against internet Denial of Service (DoS) or Distributed Denial of Service (DDoS) attacks for the transmission or receipt of WAN Data between it and the Resource Entity, ERS Resource, or QSE it represents.

[NOGRR177: Replace Section 7.1.2 above with the following upon system implementation of NPRR857:]

7.1.2 WAN Participant Responsibilities

(1) WAN Participant responsibilities include the following:

(a) A prospective WAN Participant is required to complete a WAN application, signed by the WAN Participant's Authorized Representative, and sign the ERCOT Private WAN Agreement, which governs installation, operation, and maintenance of the WAN hardware. Appropriate WAN documents can be obtained by contacting ERCOT. The WAN application shall include the following information at a minimum:

(i) WAN circuit termination location and requested functionality specifications;

(ii) WAN Participant's primary and backup contacts for WAN facilities management and services;

(iii) WAN Participant's primary and backup contacts for WAN emergency restoration;

(iv) WAN Invoicing contact information;

(v) WAN Participant's 24x7 operations desk long distance number; and

(vi) WAN Participant's 24x7 analog line for maintenance.

(b) Each WAN Participant must timely update information provided to ERCOT in the application process, and must promptly respond to any reasonable request by ERCOT for updated information regarding the WAN Participant or the information provided to ERCOT in item (a) above. Changes to any of the information listed in item (a) above shall be submitted to ERCOT using a Notice of Change of Information (NCI) form.

(c) A WAN Participant shall provide physical security systems compliant with the applicable Critical Infrastructure Protection (CIP) requirement of the North American Electric Reliability Corporation (NERC) Reliability Standards.

(d) WAN Participant equipment provided by ERCOT that exchanges ICCP Data, Resource-Specific XML Data, or operational voice communications with ERCOT shall connect directly to the ERCOT WAN. ERCOT will work with each WAN Participant to determine the most appropriate WAN demarcation point. Criteria for determining demarcation points include:

(i) Reliability;

(ii) Location of data centers;

(iii) Location of control centers and/or communication centers;

(iv) Location of disaster recovery facilities;

(v) Location of Energy and Market Management System (EMMS) equipment;

(vi) Location of ICCP equipment;

(vii) Location of Resource-Specific XML equipment; and

(viii) Location of private branch exchange (PBX) or call management equipment installation.

(e) ERCOT is responsible for the reliable transport of communications over the ERCOT WAN and will make the ultimate determination of the demarcation point location.

(f) A WAN Participant that serves both TO and QSE functions at one location may have a single ERCOT WAN connection as defined in Section 7.1, ERCOT Wide Area Network, at that location.

(g) If a TO and QSE share a centralized PBX or call management with a QSE, the QSE's OPX circuits will be terminated separately from the OPX circuits of the TO.

(h) Each WAN Participant is required to extend the ERCOT OPX and Hotline voice circuits into its 24x7 operations desk. The OPX and Hotline voice circuits are transported across the ERCOT WAN. If a WAN Participant is designated to represent another Market Participant through an agency agreement approved by ERCOT, the WAN Participant must have dedicated OPX circuits for each Market Participant represented, in addition to a dedicated OPX for the WAN Participant if it is also representing Resources. In these cases, a single Hotline button will be used for the WAN Participant and all of the represented Market Participants. The Market Participant and its agent, if applicable, are both responsible for delivering the Hotline and the OPX to the Market Participant's 24x7 operations desk in a manner that reasonably assures continuous communication with ERCOT and is not affected by calling features such as automatic transfer or roll to voice mail. Also, a touchtone keypad is required for the Hotline to be able to provide an acknowledged receipt. The demarcation point for all voice circuits is the WAN Participant's router.

(i) Each WAN Participant must provide internal facilities and communications to collect and furnish data and voice signals to the ERCOT WAN as required by the Protocols. For TOs such data includes, but is not limited to, operational voice communications, ICCP Data, and Supervisory Control and Data Acquisition (SCADA) for substations and other Transmission Facilities. For QSEs, such data includes, but is not limited to, operational voice communications, ICCP Data, Resource-Specific XML Data, and SCADA for Resources.

(j) A WAN Participant shall provide adequate physical facilities to support the ERCOT WAN communications equipment. The physical facilities and communications equipment requirements include the following:

(i) Provide an analog business phone line or PBX analog extension for troubleshooting and maintenance of equipment;

(ii) Provide a height of 24” of rack space in a 19” wide rack;

(iii) Provide two separate uninterruptible power supply single-phase 115 VAC 20 amp circuits, each with four receptacles in the 19” rack listed above;

(iv) Provide building wiring from circuit termination to equipment rack;

(v) Within 24-hours notice, provide ERCOT employees or contractors access to the communication facility;

(vi) Within one-hour notice, provide ERCOT employees or contractors emergency access to the communication facility;

(vii) Provide onsite personnel to escort ERCOT employees or contractors;

(viii) Provide a firewall or router, located at the WAN Participant site, for the network address translation of internal WAN Participant addresses to external addresses on the ERCOT LAN;

(ix) Provide connectivity from WAN Participant firewall or router to ERCOT LAN located at WAN Participant site. WAN Participants are responsible for their own security through this connection;

(x) Dual cable entrances to WAN Participant, connecting to different Telco Central Offices are highly recommended; and

(xi) Provide ERCOT with internal IP addressing scheme as needed for network design. This will be kept confidential.

(k) A WAN Participant shall supply, implement, and maintain all data and voice communication facilities required to fulfill the obligations set forth in these Nodal Operating Guides.

(l) A WAN Participant’s installation of data and voice communication facilities described in paragraph (k) above must complete qualification testing as specified by ERCOT before ERCOT will grant approval to commence operational use of the WAN connection. A WAN Participant shall request prior approval from ERCOT of any changes in data and voice communication facilities that impact connectivity through the WAN and shall coordinate with ERCOT before commencing operational use.

(m) If a WAN Participant extends its network or otherwise transmits WAN Data or operational voice communications to another of its control and/or data center or another WAN Participant’s control and/or data center, then such communications shall be transmitted or received using a Secure Private Network (SPN).

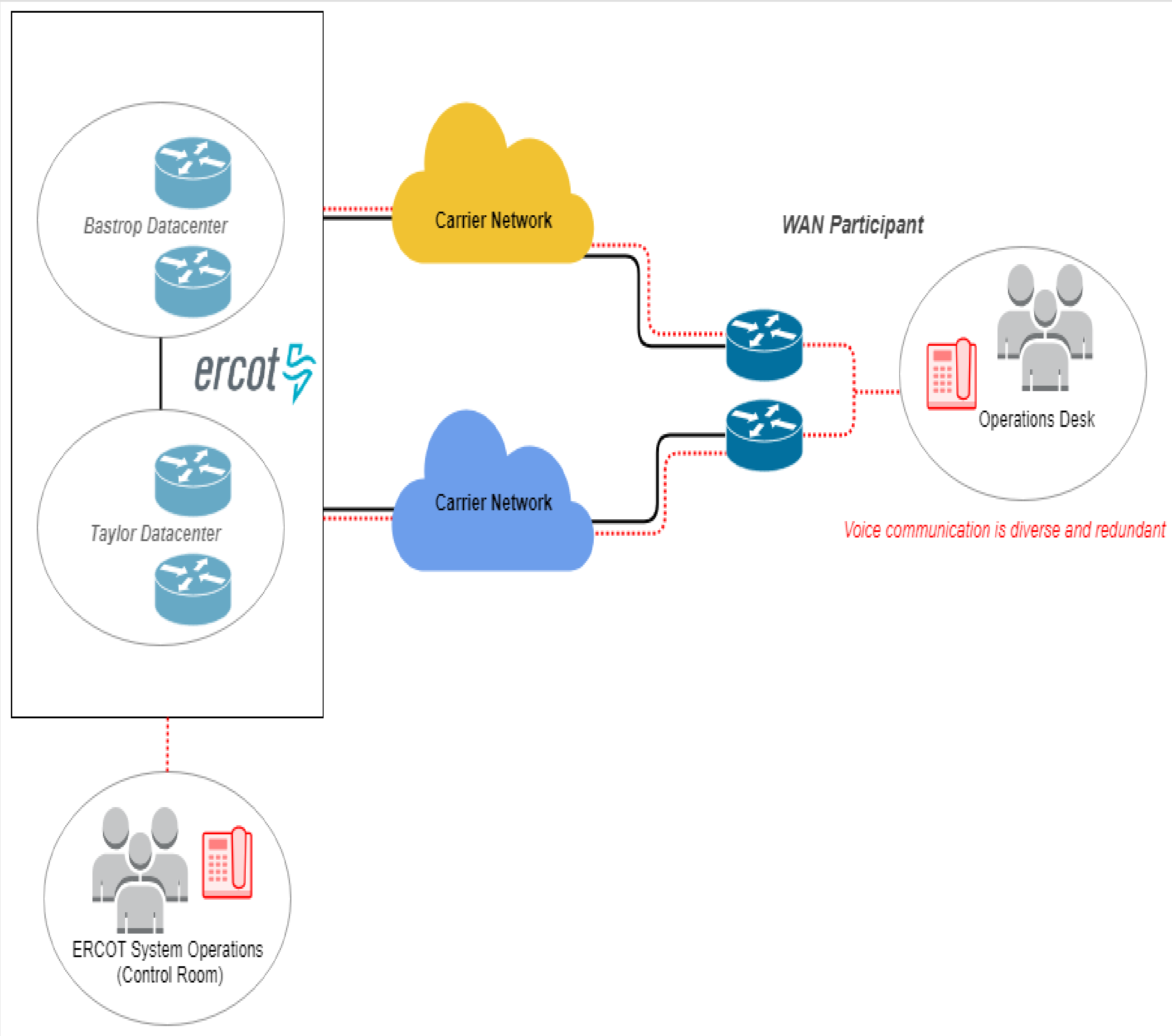

Figure 1: ERCOT Wide Area Network Overview

(n) If a WAN Participant is a QSE that represents a Resource Entity, ERS Resource, or another QSE for whom it receives or transmits WAN Data, the WAN Participant shall utilize an SPN or other network that provides equivalent protection against internet Denial of Service (DoS) or Distributed Denial of Service (DDoS) attacks for the transmission or receipt of WAN Data between it and the Resource Entity, ERS Resource, or QSE it represents.

7.1.3 *Joint Responsibilities (Maintenance and Restoration)*

(1) Joint responsibility of WAN Participants and ERCOT include the following:

(a) Coordinate maintenance and restoration activities so its reliability is not compromised;

(b) All primary and back-up circuits shall be tested annually or as otherwise requested by ERCOT for end-to-end performance;

(c) ERCOT will specify test procedures for hotline and any back-up or alternate path voice circuits;

(d) A WAN Participant shall troubleshoot WAN connectivity or performance as directed by ERCOT;

(e) If WAN performance issues arise, a Market Participant shall take action to isolate circuit and equipment problems for quick resolution and restoration of service; and

(f) Scheduled maintenance of any WAN hardware/software shall be coordinated between ERCOT and the affected WAN Participant. The WAN Participant shall provide reasonable outage windows for ERCOT support personnel to upgrade and repair equipment and shall coordinate with ERCOT before commencing operational use.

7.2 ERCOT ICCP Interface

(1) The Inter-Control Center Communications Protocol (ICCP) over the ERCOT Wide Area Network (WAN) provides the Real-Time telemetry data from Market Participant computers, computer networks, or other devices. Market Participants providing the data using an ICCP link must format their data and coordinate installation according to the ERCOT WAN Agreement found in the ERCOT Nodal ICCP Communication Handbook. The ERCOT Nodal ICCP Communication Handbook provides additional details and shall be used in conjunction with the Protocols and Operating Guides to facilitate the communication needs of ERCOT and Market Participants to effectively manage system and market requirements. Updates to the ERCOT Nodal ICCP Communication Handbook shall be approved by the Technical Advisory Committee (TAC).

7.2.1 *Quality Codes*

(1) Status and analog telemetry data provided to ERCOT shall have the associated quality codes and associated attributes found in the ERCOT Nodal ICCP Communication Handbook. ICCP quality codes to be provided to ERCOT by the Market Participant and to the Market Participants by ERCOT shall follow the standards set in the ERCOT Nodal ICCP Communication Handbook.

7.2.2 Metric of Availability

(1) ICCP links must achieve availability as required by the Protocols. Availability metrics shall establish a process to coordinate downtime for ICCP links and database maintenance.

(2) ICCP links shall use fully redundant data communication from the Qualified Scheduling Entity (QSE) and Transmission Service Provider (TSP) control systems to the ERCOT System as required by the Protocols.

[NOGRR177: Replace paragraph (2) above with the following upon system implementation of NPRR857:]

(2) ICCP links shall use fully redundant data communication from the WAN Participant control systems to the ERCOT System as required by the Protocols.

7.3 Telemetry

(1) Qualified Scheduling Entities (QSEs) and Transmission Service Providers (TSPs) required to supply Real-Time telemetry data to ERCOT shall use an Inter-Control Center Communications Protocol (ICCP) interface through the ERCOT Wide Area Network (WAN). TSPs and QSEs shall also receive signals from ERCOT over the ICCP interface.

(2) Each QSE and TSP shall continuously provide to ERCOT the telemetry data quantities that they are responsible for in the format described in the ERCOT Nodal ICCP Communication Handbook. The frequency of updates, means of communication to ERCOT, and data format for each point provided by each Entity shall follow the specifications in the ERCOT Nodal ICCP Communication Handbook. At the frequency specified, each update cycle shall provide current operating data for all points being monitored. Design accuracy and availability of data points delivered to ERCOT shall satisfy the requirements of the Protocols pursuant to Protocol Section 3.10.7.5, Telemetry Requirements.

(3) QSEs, Resources and TSPs are required to provide power operation data to ERCOT according to the Protocols and the ERCOT Nodal ICCP Communication Handbook.

(4) The nomenclature format of data (i.e. structure of the ICCP Object Name) shall follow the standards in the ERCOT Nodal ICCP Communication Handbook.

[NOGRR177: Replace Section 7.3 above with the following upon system implementation of NPRR857:]

(1) WAN Participants required to supply Real-Time telemetry data to ERCOT shall use an Inter-Control Center Communications Protocol (ICCP) interface through the ERCOT Wide Area Network (WAN). WAN Participants shall also receive signals from ERCOT

over the ICCP interface.

(2) Each WAN Participant shall continuously provide to ERCOT the telemetry data quantities that they are responsible for in the format described in the ERCOT Nodal ICCP Communication Handbook. The frequency of updates, means of communication to ERCOT, and data format for each point provided by each Entity shall follow the specifications in the ERCOT Nodal ICCP Communication Handbook. At the frequency specified, each update cycle shall provide current operating data for all points being monitored. Design accuracy and availability of data points delivered to ERCOT shall satisfy the requirements of the Protocols pursuant to Protocol Section 3.10.7.5, Telemetry Requirements.

(3) WAN Participants are required to provide power operation data to ERCOT according to the Protocols and the ERCOT Nodal ICCP Communication Handbook.

(4) The nomenclature format of data (i.e. structure of the ICCP Object Name) shall follow the standards in the ERCOT Nodal ICCP Communication Handbook.

7.3.1 Data from ERCOT to QSEs

(1) ERCOT shall provide all required data and issue instructions over the ERCOT WAN to QSEs in accordance with the Protocols and the ERCOT Nodal ICCP Communication Handbook.

(2) ERCOT shall follow data requirements and standards described in the ERCOT Nodal ICCP Communication Handbook.

7.3.2 Data from ERCOT to TSP

(1) ERCOT shall provide operational data over the ERCOT WAN to the TSP in accordance with the Protocols and the ERCOT Nodal ICCP Communication Handbook.

(2) ERCOT is required to provide operational data to TSPs for the purpose of providing reliability information on current conditions. TSPs may request QSE supplied data as allowed by the Protocols.

(3) ERCOT will post notice to WAN Participants of all available data.

[NOGRR177: Replace applicable portions of Section 7.3.2 above with the following upon system implementation of NPRR857:]

7.3.2 Data from ERCOT to TSPs and DCTOs

(1) ERCOT shall provide operational data over the ERCOT WAN to TSPs and DCTOs in

accordance with the Protocols and the ERCOT Nodal ICCP Communication Handbook.

(2) ERCOT is required to provide operational data to TSPs and DCTOs for the purpose of providing reliability information on current conditions. TSPs may request QSE supplied data as allowed by the Protocols.

(3) ERCOT will post notice to WAN Participants of all available data.

7.3.3 Data from WAN Participants to ERCOT

(1) Each WAN Participant shall provide telemetered measurements over the ERCOT WAN on modeled Transmission Elements as required by the Protocols and the ERCOT Nodal ICCP Communication Handbook.

(2) WAN Participants shall provide Real-Time monitoring of power system quantities to ERCOT as defined in the Protocols and the ERCOT Nodal ICCP Communication Handbook. ERCOT shall work with WAN Participants to determine the required data using the methodology presented in the Protocols. Transmission Element status and analog measurements that the TSPs and QSEs define in the Network Operations Model shall, at a minimum, be provided to ERCOT. Ultimately, it is the responsibility of the TSPs and QSEs to provide all data requested by ERCOT.

(3) Real-Time telemetry data from QSEs used to supply power or Ancillary Services shall be integrated by ERCOT and checked against settlement meter values on a monthly basis.

(4) Each QSE and Transmission Operator (TO) shall notify ERCOT as soon as practicable when there are known telemetry data issues (telemetry data will not be available or is unreliable for operational purposes). Each QSE or TO shall address the known telemetry data issue with either a correction of the telemetry data as soon as practicable, or a manual data replacement, if available, as soon as practicable. The report, as outlined in Section 9.2.2, Real-Time Data Monitor, will contain unavailability data associated with Planned Outages of RTUs.

(5) If the QSE or TO cannot resolve the telemetry data issue within two Business Days, it shall provide an estimated time of resolution. Each QSE and TO shall notify ERCOT as soon as practicable when the telemetry data issue is resolved.

[NOGRR177: Replace Section 7.3.3 above with the following upon system implementation of NPRR857:]

7.3.3 Data from WAN Participants to ERCOT

(1) Each WAN Participant shall provide telemetered measurements over the ERCOT WAN on modeled Transmission Elements as required by the Protocols and the ERCOT Nodal

ICCP Communication Handbook.

(2) WAN Participants shall provide Real-Time monitoring of power system quantities to ERCOT as defined in the Protocols and the ERCOT Nodal ICCP Communication Handbook. ERCOT shall work with WAN Participants to determine the required data using the methodology presented in the Protocols. Transmission Element status and analog measurements that the Transmission Operators (TOs) and QSEs define in the Network Operations Model shall, at a minimum, be provided to ERCOT. Ultimately, it is the responsibility of the TOs and QSEs to provide all data requested by ERCOT.

(3) Real-Time telemetry data from QSEs used to supply power or Ancillary Services shall be integrated by ERCOT and checked against settlement meter values on a monthly basis.

(4) Each QSE and TO shall notify ERCOT as soon as practicable when there are known telemetry data issues (telemetry data will not be available or is unreliable for operational purposes). Each QSE or TO shall address the known telemetry data issue with either a correction of the telemetry data as soon as practicable, or a manual data replacement, if available, as soon as practicable. The report, as outlined in Section 9.2.2, Real-Time Data Monitor, will contain unavailability data associated with Planned Outages of RTUs.

(5) If the QSE or TO cannot resolve the telemetry data issue within two Business Days, it shall provide an estimated time of resolution. Each QSE and TO shall notify ERCOT as soon as practicable when the telemetry data issue is resolved.

7.3.3.1 Weather Zone Data

(1) A TSP that is responsible for providing Weather Zone tie-line measurement data to ERCOT is required to establish a backup to the primary source.

(2) TSPs having an Energy Management System (EMS) with a native ICCP application capable of four second periodic data set transfers with minimum 300 points per data set, and hot standby backup ICCP servers with automatic fail-over capability, shall provide an additional ICCP association across the ERCOT WAN for the transfer of Weather Zone tie line measurements. ICCP nodes should exist at primary and backup facilities.

7.3.4 Resolving Real-Time Data Issues that affect ERCOT Network Security Analysis

(1) Real-Time telemetry data issues that affect ERCOT's Network Security Analysis (NSA) are issues that cause invalid State Estimator solutions.

(2) Manually replaced telemetry data is data entered by a QSE or TO on their systems that is transmitted to ERCOT via ICCP in place of the normal points experiencing an issue.

(3) ERCOT shall notify the QSE or TO responsible for the telemetry data when a Real-Time telemetry data issue affects ERCOT's NSA. ERCOT shall request each QSE or TO address the Real-Time telemetry data issue with either manually replaced telemetry data if secondary sources are available or correction of the telemetry data issue as soon as practicable. If the QSE or TO cannot address the issue within 10 minutes of notification, the QSE or TO shall coordinate with ERCOT to verbally agree to the best assumed data value(s). The QSE or TO shall use verbally agreed data to manually replace the data point to reflect the best assumed data value(s). The QSE or TO and ERCOT shall review the manually replaced telemetry data; the QSE or TO shall update the manually replaced telemetry data to reflect the best assumed data value(s) until the Real-Time data issue is resolved.

(4) If the QSE or TO cannot resolve the Real-Time telemetry data issue that is affecting ERCOT's NSA within two Business Days, it shall provide an estimated time of resolution. Each QSE or TO shall notify ERCOT when the Real-Time telemetry data issue that was affecting ERCOT's NSA is resolved.

7.3.5 TSP and QSE Telemetry Restoration

(1) Real-Time telemetry data shall be restored using criteria and procedures pursuant to Protocol Section 3.10.7.5, Telemetry Requirements.

[NOGRR177: Replace Section 7.3.5 above with the following upon system implementation of NPRR857:]

7.3.5 TO and QSE Telemetry Restoration

(1) Real-Time telemetry data shall be restored using criteria and procedures pursuant to Protocol Section 3.10.7.5, Telemetry Requirements.

7.3.6 General Telemetry Performance Criterion

(1) All Real-Time telemetry as required by the Protocols shall meet the State Estimator requirements pursuant to Protocol Section 3.10.9, State Estimator Requirements, and the telemetry requirements pursuant to Protocol Section 3.10.7.5, Telemetry Requirements.

7.4 Calibration and Testing of Telemetry Responsibilities

(1) It is the responsibility of the owner of telemetry equipment to ensure that calibration, testing and other routine maintenance of equipment is performed consistently with the provisions of the Protocols and Good Utility Practice.

ERCOT Nodal Operating Guides
Section 8
Attachment A

Detailed Black Start Information

November 1, 2016

This attachment and Section 8, Attachment E, Black Start Plan Template, provide the minimum information necessary to be used in conjunction with the ERCOT Black Start Plan. Each Transmission Operator (TO), Qualified Scheduling Entity (QSE) representing Black Start Resources, and Black Start Generation Resource should use this information for technical reference, development of Black Start plans, and training of personnel.

CONSIDERATIONS FOR SYSTEM RESTORATION

Determining System Status

(1) If a Generation Resource or Transmission Operator (TO) loses voltage on all busses and incoming transmission lines, then operators should assume there is a Partial Blackout or Blackout. If possible, the TO shall also immediately notify ERCOT. Contracted Black Start Resources shall implement Black Start procedures and establish contact with their TOs. Other Generation Resources shall contact their QSEs and then wait for instructions from the TOs. If possible, ERCOT will update TOs and QSEs concerning the status of the ERCOT System by use of the ERCOT Hotline or other available backup communications.

(2) It is expected that if communication with ERCOT is not possible, TOs will evaluate system conditions and proceed independently with their Black Start plans.

(3) Priority should be given to determining the status of nuclear Generation Resources and switchyards in order to re-establish offsite power supply.

(4) System status conditions to be surveyed include but are not limited to:

  (a) Areas of the system that are de-energized;

  (b) Areas of the system that are functioning;

  (c) Amount of generating reserve available in functioning areas;

  (d) Generation Resource availability and time required to restart;

  (e) Status of transmission breakers and sectionalizing equipment along Cranking Paths and Synchronization Corridors, and at Generation Resources;

  (f) Status of transmission breakers and sectionalizing equipment at Direct Current Ties (DC Ties);

  (g) Status of fuel supply from external suppliers;

  (h) Under-frequency relay operation; and

  (i) Relay flags associated with circuits tripped by protective relays.

Verifying Communications

(1) Reliable communications will be the key to a safe and timely restoration following a Partial Blackout or Blackout. As part of the initial assessment after a Partial Blackout or Blackout, communication facilities shall be tested and verified. It is possible, especially in case of a Blackout, that communications with out-of-state QSEs representing Generation Resources may not be possible. It is therefore critical that TOs and Generation Resources located within their transmission system be able to communicate directly during these times.

(a) The ERCOT System Operators shall:

(i) Verify or establish communication paths with TOs;

(ii) Verify or establish communications paths with QSEs representing Generation Resources;

(iii) Verify integrity of ERCOT Hotline;

(iv) Periodically disseminate information to TOs and QSEs; and

(v) Direct implementation of Black Start plan in areas of a Partial Blackout or Blackout.

(b) The TO operators shall:

(i) Contact ERCOT in order to report status;

(ii) Establish contact with contracted Black Start Resources and their QSE(s);

(iii) Initiate Black Start plan; and

(iv) Establish communication paths with other Generation Resources necessary to the restoration of the ERCOT System.

(c) The QSE representing Generation Resources shall:

(i) Contact ERCOT to report status of Generation Resources within the ERCOT Region;

(ii) Assist TOs as required; and

(iii) Ensure Generation Resources are prepared to receive and follow instructions directly from the TO to which they are connected.

(d) The Black Start Resources shall:

(i) Isolate their Black Start Resource from the ERCOT Transmission Grid;

(ii) Establish communications with their TOs;

(iii) If no communications with the TOs are available, establish communications with ERCOT; and

(iv) Start Black Start Resource and request load interconnection from TO. The Black Start Resource shall not connect to the ERCOT Transmission Grid without specific instructions to do so from either ERCOT or the designated TO responsible for the Black Start Resource.

(2) Should problems be encountered with any of the primary communication facilities, back-up facilities shall be deployed and appropriate personnel notified.

(3) Communications will be vital to an orderly recovery. To keep communication facilities available, operating personnel shall ensure that three-part communication is used at all times.

Preparing for System Restoration

(1) Orderly restoration will usually require sectionalizing the de-energized parts of the ERCOT System into smaller, manageable blocks before they are energized.

(2) The sectionalizing process should usually address but is not limited to the following objectives:

(a) Priority shall be given to restoring offsite power to nuclear Generation Resources;

(b) Ensure that blocks of load to be energized are sized to minimize the problems of cold load pickup; and

(c) Operators shall verify that their switching orders as well as any standing emergency switching orders have been completed.

Bringing Up Generation Resources

(1) First priority shall be given to preventing damage to Generation Resource equipment and to restoring offsite power to nuclear Generation Resources. Secondly, attention shall be given to preparing generators that can come On-Line most rapidly. All operators should remember that large steam Generation Resources will need an outlet for the minimum generation requirement soon after coming On-Line.

(2) A Black Start Resource has procedures to begin the process of bringing its generators back up when the switchyard and all incoming transmission lines are de-energized. The Generation Resource shall not synchronize or pick up load without communicating with the TO to which it is connected.

(3) A Generation Resource without Black Start capability shall have a written procedure in place to begin preparing the Generation Resource to be energized from an external line.

When the TO has energized the Generation Resource switchyard it will contact the Generation Resource directly and the QSE as soon as practical. The TO will coordinate starting of large motors, bringing Generation Resources On-Line, and synchronizing Generation Resources with the rest of the ERCOT Transmission Grid.

(4) Generation Resource operators will be controlling system frequency during the recovery period and must keep it between trip points for generators' under-frequency and over-frequency relays. It is preferable to use the generators with lowest under-speed trip for initial restoration.

(5) Automatic Voltage Regulators (AVRs) should be placed in service as soon as practical after bringing Generators On-Line and should remain in-service to improve machine stability.

(6) As soon as possible, after bringing a Generator On-Line, automatic Governor controls should be placed in the "automatic" position to ensure instantaneous Governor response to changes in frequency.

Picking Up Lines

(1) Ties between nearby Generation Resources shall be established as soon as possible. Priority shall be given to restoring at least one circuit to nuclear Generation Resources to provide offsite power for safe shutdown.

(2) A line should be energized from the strongest electrical source. Switching devices on all substation or transmission capacitor banks along the line should be open unless needed for voltage control.

(3) Energizing transmission auto-transformers (345/138 kV, 138/69 kV) and shunt reactors at Generation Resource will allow plant operators to increase field current on the generator to increase stability. Also, this reactive current will help keep transmission voltages from becoming excessive.

(4) Caution should be exercised in the use of 345 kV transmission system. Because of high values of line charging, energizing one of these circuits with little or no load can produce excessive voltage and can damage substation equipment (Note: 345kV lines supply approximately 1 MVAr/mile of line charging while 138kV lines supply approximately 0.1 MVAr/mile).

(5) Operators in TO control rooms should exercise care when energizing transmission lines, so that they do not close a breaker into a fault. Operators in TO control rooms should be aware of any transmission lines that tripped while the system was going down and have field personnel check the relay flags before energizing the line.

(6) Ferroresonance may occur while energizing a line or while picking up a transformer from an unloaded line. Operators in TO control rooms should be on guard for unusually high and sustained voltages during such switching. 345 kV lines may be highly susceptible to this phenomenon and their use should be minimized in the early stages of restoration.

(7) Impedance relays that do not have out of step blocking may trip lines due to power swings during restoration (a good indication that the line tripped due to excessive power swings rather than a fault is the existence of impedance relay flags and no ground flags).

Picking Up Load

(1) In general, 69 kV and 138 kV lines along with radial 345 kV lines to autotransformers may be used to energize load. When energizing a 345 kV circuit and autotransformer combination, both the line and transformer should be energized at the same time to avoid the problem of excessive voltage. The more lightly loaded a generator is, the less load increment it can safely pick up.

(2) Cold load pick up can involve inrush currents of ten or more times than the normal load current depending on the nature of the load being picked up. This will generally decay to about two times the normal load current in two to four seconds and remain at a level of 150% to 200% of pre-shutdown levels for as long as 30 minutes.

(3) Priority shall be given to restoring offsite power to nuclear Generation Resources. As critical and priority loads are restored, consideration should be given to restoration of loads controlled by under-frequency relays.

(4) When energizing load, the operators in TO control rooms must be in close contact with the Generation Resource in order that excessive load is not picked up on a generator in one operation. Generally, the operators in TO control rooms should pick up no more than 5% of the total generating capability in an Island in a single step. If load is picked up in blocks that are too large, then the inrush current may operate over current relays that trip the loads off the ERCOT System again. There should be sufficient time between switching operations to allow the generator to recover from the sudden increase in load.

(5) The operators in TO control rooms should exercise caution when loading a single generator to more than 50% of its control range until additional generators have been brought back On-Line in that Island. Generally, no generator should be loaded to more than 80% of its available capability until ERCOT System conditions return to normal.

(6) Since each Generation Resource may be operating independently, Generation Resource operators will have to monitor and adjust their generators voltage and frequency. Frequency should be kept above 59.8 Hz and as close as possible to 60 Hz. Voltage should be kept as close as possible to normal schedules. As more generators are brought up and more load is added, the voltage and frequency will tend to stabilize.

(7) Residential and commercial load will most likely be easier to pick up and maintain than industrial loads. This is due to the large fluctuation possible with industrial loads.

(8) The operators in TO control rooms should exercise caution when re-energizing capacitor banks after load has been picked up. The change in system voltage that occurs will be much larger than normal because of the reduced system fault duty.

Synchronizing Between Islands

(1) TOs shall have field personnel in area Islands to check breakers at each end of a line being used to synchronize between Islands to ensure they are open regardless of supervisory indication. The area with the largest amount of generation On-Line shall energize the line first.

(2) Where available, field personnel shall synchronize and close the tie breakers at the synchronization point. If there is a sufficient frequency difference that the Islands cannot be synchronized, the Island with the least generation On-Line shall adjust its frequency to achieve synchronization.

(3) When synchronizing, both the phase angle across the breaker, and the voltage on each side of the breaker shall be measured. If possible, the phase rotation should be stopped and the phase angle reduced to 10° or less before closing the breakers.

(4) In general, lines should not be loaded to more than 50% of thermal rating until multiple tie paths have been established. Additional ties should be closed as soon as possible.

ERCOT COORDINATION

(1) During the initial stages of the restoration ERCOT will coordinate the Black Start restoration effort by monitoring the implementation of each TO's Black Start plan, providing ERCOT System status information, and facilitating communication between the Market Participants. ERCOT will also monitor the changes in Resource conditions, restoration of transmission lines, and any load that is re-energized. The ERCOT Hotline or available backup communications will periodically be used to communicate simultaneously with the Market Participants on a periodic basis assuming communication is possible.

(2) System status conditions that should be surveyed include, but are not limited to:

(a) Communication facilities;

(b) Transmission system;

(c) Generating system;

(d) Fuel supplies; and

(e) Any other significant conditions which might affect restoration.

(3) ERCOT System Operators should be sure that each TO is successfully implementing their Black Start plan and each Generation Resource is successfully implementing their written procedures for preparing their Generation Resources to be energized during Black Start restoration. ERCOT System Operators will direct mutual assistance by utilizing the Black Start map and contacting the Market Participants most able to provide the assistance.

(4) Before synchronization of intercompany Islands ERCOT will designate the entity responsible for frequency control in the combined Islands. Initially this may be a single Generation Resource. As the restoration effort progresses, ERCOT will work to combine Islands in such a way as to restore frequency control of one of the QSEs representing Generation Resources. As Inter-company Islands are synchronized ERCOT will approve the addition of generation and load to the ERCOT System. No additions shall be made without that approval.

CONSIDERATIONS FOR BLACK START TESTING

(1) ERCOT shall maintain a record of contracted Black Start Resources and update such records on an annual basis. The record shall include the name, location, MW capability, type of unit, date of test, and starting method of each Black Start Resource per the North American Electric Reliability Corporation (NERC) Reliability Standards.

(2) The owner or operator of each Black Start Resource shall demonstrate through the testing procedures outlined in Protocol Section 8.1.1.2.1.5, System Black Start Capability Qualification and Testing, that the Black Start Resource can perform its intended functions as required in the ERCOT Black Start Plan. ERCOT may also order random simulation or testing of Black Start capabilities. Documentation of the analysis shall be provided to NERC, the NERC Regional Entity, or the Reliability Monitor upon request as required by the NERC Reliability Standards.

CRITERIA FOR ERCOT AND TRANSMISSION OPERATOR BLACK START PLANS

(1) ERCOT will maintain a Black Start Plan that is consistent with this Operating Guide. The ERCOT Black Start Plan shall be provided to the QSEs representing Black Start Resources and TOs.

(2) ERCOT System Operators shall review these documents on a regular basis. It is suggested that all Black Start plans include at a minimum the following elements:

(a) Strategies and guidelines for restoration of the ERCOT System;

(b) Identification of the relationships and responsibilities of the QSEs representing Black Start Resources and TO personnel necessary for the restoration;

(c) Identification of Black Start Resources including:

(i) Generation Resources;

(ii) Transmission Facilities;

(iii) Communication resources; and

(iv) Fuel resources.

(d) Mutual assistance arrangements;

(e) Contingency plans for failed Generation Resources;

(f) Identification of critical load requirements;

(g) Identification of special equipment requirements;

(h) General instructions and guidelines for ERCOT System Operators, Resource Entities, QSEs representing Generation Resources, and TO operators and their respective communications personnel;

(i) Procedures for Notification; and

(j) Procedures for return to Market Operations.

(3) TO's Black Start plans shall include sections on the Black Start Purpose, Scope, Roles and Responsibilities, Strategies, Priorities, Operations, Communication, and Contingency plans and shall follow the format outlined in Appendix 8E.

ERCOT Nodal Operating Guides
Section 8
Attachment B:

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April 1, 2014

Attachment B

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ERCOT Nodal Operating Guides
Section 8
Attachment C

Turbine Governor Speed Tests

December 5, 2025

TURBINE GOVERNOR SPEED REGULATION TEST FOR MECHANICAL-HYDRAULIC GOVERNOR

GENERAL INFORMATION

Unit Code (16 characters): _______________ Location (County): ______________________

Unit Name: ___________________________ Date of test: ___________________________

QSE: _________________________________ Resource Entity: _______________________

Steady State Speed Regulation at High-Speed Stop

$$Rs = \frac{(A - B) \times 100}{3600}$$

Where:

A = Speed with speed changer set at high-speed stop and with throttle (or stop) valves open and machine running idle on the Governor.

B = Speed with speed changer set at high-speed stop and when governing valves just reach wide-open position.

Steady State Speed Regulation at Synchronous Speed [1]

$$Rs = \frac{(C - D) \times 100}{3600}$$

Where:

C = Speed with speed changer set for synchronous speed and with throttle (or stop) valves open and machine running idle on the Governor.

D = Speed with speed changer set at the same position as in C above and when governing valves just reach wide open position.

Steady State Speed Regulation at Low-Speed Stop

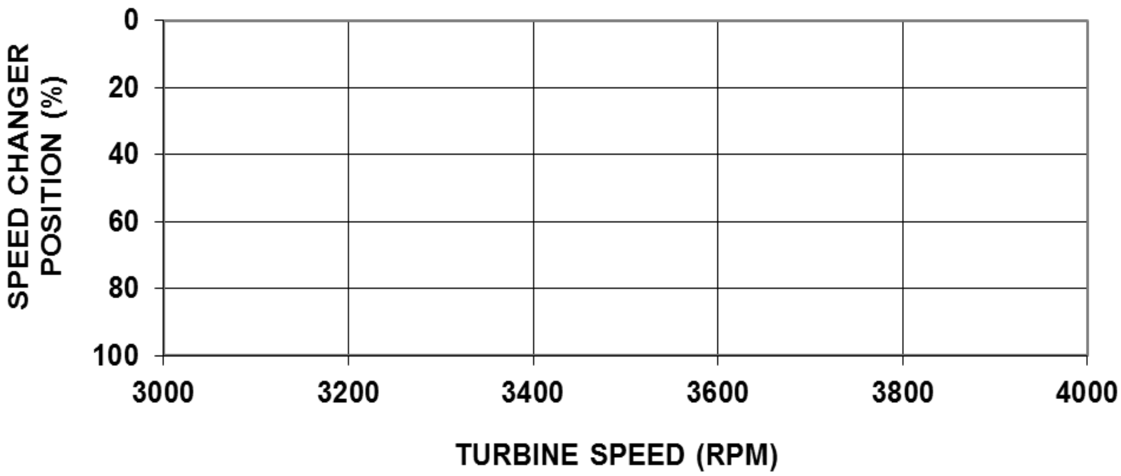
$$Rs = \frac{(E - F) \times 100}{3600}$$

Where:

[1] Westinghouse recommends using only this test.

E = Speed with speed changer set at low-speed stop and with throttle (or stop) valves open and machine running idle on the Governor.

F = Speed with speed changer set at low-speed stop and when governing valves just reach wide-open position.



E, F @ Low Speed Stop
C, D @ Sync. Speed
A, B @ High Speed Stop

Test Data

Point	A	B	C	D	E	F
Speed, RPM						
Frequency Hz						

Speed Changer Travel Time:

(a) From Low-Speed Stop to High-Speed Stop in _________seconds.
(b) From High-Speed Stop to Low-Speed Stop in _________seconds.

Over-speed Trip Test Speed at _________rpm.

Comments:____
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____
____
____

SUBMITTAL

Resource Entity Representative: ____

QSE Representative: ______________________________

Date submitted to ERCOT Representative: ______________________________

EXAMPLE OF A TURBINE GOVERNOR SPEED REGULATION TEST FOR MECHANICAL-HYDRAULIC GOVERNOR

Steady State Speed Regulation at High-Speed Stop

$$Rs = \frac{(A - B) \times 100}{3600} = \frac{(3850 - 3570) \times 100}{3600} = 7.78\%$$

Where:

A = Speed with speed changer set at high-speed stop and with throttle (or stop) valves open and machine running idle on the Governor.

B = Speed with speed changer set at high-speed stop and when governing valves just reach wide-open position.

Steady State Speed Regulation at Synchronous Speed [2]

$$Rs = \frac{(C - D) \times 100}{3600} = \frac{(3600 - 3310) \times 100}{3600} = 8.06\%$$

Where:

C = Speed with speed changer set for synchronous speed and with throttle (or stop) valves open and machine running idle on the Governor.

D = Speed with speed changer set at the same position as in C above and when governing valves just reach wide open position.

Steady State Speed Regulation at Low-Speed Stop

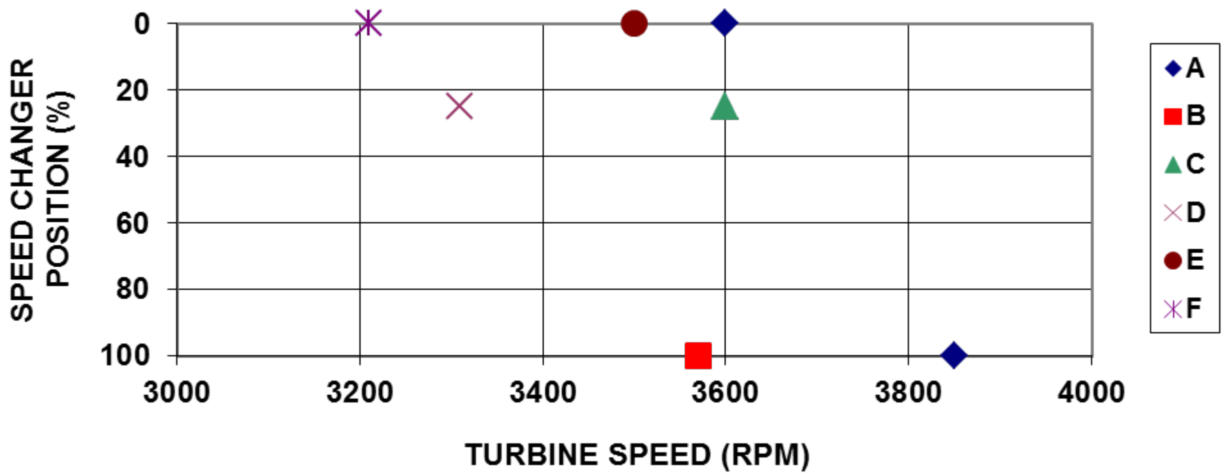
$$Rs = \frac{(E - F) \times 100}{3600} = \frac{(3500 - 3210) \times 100}{3600} = 8.06\%$$

Where:

E = Speed with speed changer set at low-speed stop and with throttle (or stop) valves open and machine running idle on the Governor.

[2] Westinghouse recommends using only this test.

F = Speed with speed changer set at low-speed stop and when governing valves just reach wide-open position.



E, F @ Low Speed Stop
C, D @ Sync. Speed
A, B @ High Speed Stop

Test Data

Point	A	B	C	D	E	F
Speed, RPM	3850	3570	3600	3310	3500	3210
Frequency Hz	64.2	59.5	60.0	55.0	58.3	53.5

Speed Changer Travel Time:

(a) From low-speed stop to high-speed stop in 73 seconds.

(b) From high-speed stop to low-speed stop in 74 seconds.

Over-speed trip test speed at _3965__rpm.

Comments:____

TURBINE GOVERNOR SPEED REGULATION TEST FOR ELECTRO-HYDRAULIC GOVERNOR

GENERAL INFORMATION

Unit Code (16 characters): _______________ Location (County): ______________________

Unit Name: ____________________________ Date of test: ____________________________

QSE: __________________________________ Resource Entity: ________________________

Turbine Governor Speed Regulation Test Procedures

(a) Simulate unit On-Line and turbine speed at 3600 RPM.

(b) Set Load reference at minimum value.

(c) Monitor valve demand signal and record as value "A" (in %).

(d) Reduce speed until valve demand just reaches maximum value. Record valve demand as value "B" (in %) and speed as value "C" (in RPM).

(e) Set speed at 3600 and Load reference at maximum value.

(f) Monitor valve demand signal and record as value "D" (in %).

(g) Increase speed until valve demand just reaches minimum value. Record valve demand as value "E" (in %) and speed as value "F" (in RPM).

Turbine Governor Speed Regulation Test Results

	A	B	C	D	E	F
Valve Demand (%)						
Speed (rpm)						

Speed Regulation With Decreasing Speed

$$R_D = \frac{100}{(B-A)} \times \frac{(3600-C)}{3600} \times 100$$

Speed Regulation With Increasing Speed

$$R_I = \frac{100}{(D-E)} \times \frac{(F-3600)}{3600} \times 100$$

Comments: ____

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SUBMITTAL

Resource Entity Representative: ______________________________

QSE Representative: ______________________________

Date submitted to ERCOT Representative: ______________________________

DEFINITIONS

System Frequency Response	This response is a function of two key variables: the Primary Frequency Response from Governors and Load dampening of the connected Load.
Percent Droop Settings	Also known as Frequency Regulation, Speed Regulation, Speed Sensitivity, Speed Error and others. Percent droop is the percent change in nominal frequency that will cause generator output to change from no Load to full Load. For synchronous Resources, it is the change in steady state rotor speed, expressed in percent of rated speed, when power output is gradually reduced from rated to zero power. A common percent droop setting is 5% for both high and low frequency excursions.
Dead-Band	The range of deviations of system frequency (+/-) that produces no Governor response, and therefore, no frequency (speed) regulation. It is expressed in percent of rated speed, Hz, or RPM.
Valve Position Limiter	A device that acts on the speed and Load governing system to prevent the Governor-controlled valves from opening beyond a pre-set limit.
Blocked Governor Operation	Operating the generating unit with the control system adjusted to prevent the turbine governor from responding to system frequency (speed) variations. In an effort to reduce speed Governor operation in some generating units, turbine control systems can be adjusted to block

the operation of the Governor after the unit is in parallel with the system and is running at its desired output. Selection of a high percent droop characteristic or a large Governor Dead-Band constitutes a form of blocked Governor action.

Variable Pressure Operation Varying the boiler pressure to improve turbine efficiency at lower Loads. Two methods are normally used. The first method, the turbine control (G.E.) or Governor (Westinghouse) valves are positioned in the wide-open position and the generator is changed by changing the boiler pressure. With this method, there is very little, if any response to frequency excursions. The second method, the valves are positioned at approximately 50% open. The valves are still able to respond to system disturbances. Normal changes in generation requirements are made by varying the boiler pressure until the unit is at rated pressure. After full pressure is reached, the turbine valves are used to make the required generation changes.

GENERATION RESOURCE FREQUENCY RESPONSE TEST PROCEDURE

DESCRIPTION OF THE TEST

1. The frequency response function of the Generation Resource is tested On-Line at a Load level that allows the Generation Resource to increase or decrease Load without reaching low operating limits or high operating limits. If the Generation Resource cannot be tested On-Line then it will notify ERCOT that it will be conducting an Off-Line test. The recommended level is 92% Base Load or below.

2. The test is performed by adding a frequency offset signal that exceeds the Governor Dead-Band value to the measured frequency signal. This should create immediate step change in the measured frequency signal.

3. The test starts at time t0 when the frequency Dead-Band is exceeded and signal “Generation Resource Frequency Response On” becomes active.

4. The following signals should be recorded at least two seconds: Unit MW Output, “Generation Resource Frequency Response On.”

5. The duration of the test is 100 seconds. After 100 seconds, the offset signal should be removed and the Generation Resource should return to pretest power output.

6. The test should be conducted both with positive and negative frequency offsets.

7. The test is considered successful after the signal becomes active if at least 70% of the calculated MW contribution is delivered within 16 seconds and the response is maintained for an additional 30 seconds.

8. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7, Turbine Speed Governors.

DEFINITIONS

Generation Resource Base Load = Maximum Droop Response Range (MDRR)

Gain MW for 0.1Hz = $\dfrac{P}{(Droop * 60 - GovernorDead - Band) * 10}$

Where:

P = Generation Resource Base Load (MW)

$Droop$ = droop (%)

Frequency Offset = +0.2 Hz and -0.2 Hz (+12 rpm and -12 rpm, for 3600 sync speed machines), outside Governor Dead-Band

Test frequency = Measured Frequency + Frequency Offset

MW Contribution = Gain MW to 0.1 Hz *10*Frequency Offset

Calculated droop = - $\dfrac{P * \Delta Hz}{60 * \Delta MW}$

Where:

P = Generation Resource Base Load (MW)

ΔHz = Change in frequency (Hz), taking into account Governor Dead-Band

ΔMW = Change in power output (MW)

EXAMPLE

Generation Resource Base Load = 150 MW

Droop = 0.05 or 5% (use 0.05 for calculation)

Governor Dead-Band = 0.034

Gain MW to 0.1 Hz = $\dfrac{150}{[(0.05 * 60) - 0.034] * 10}$ = +/- 5.06 MW/0.1 Hz

MW Contribution = 5.06*10*+/- (0.2) = +/-10.12 MW

Expected under-frequency response: +10.12 MW in 16 sec. for -0.2 Hz offset
Expected over-frequency response: -10.12 MW in 16 sec. for +0.2 Hz offset

Minimum accepted under-frequency response: +7.08 MW in 15 sec. for -0.2 Hz offset
Minimum accepted over-frequency response: -7.08 MW in 15 sec. for +0.2 Hz offset

Calculated droop for 8 MW increase in power output in 16 sec. for -0.2 Hz offset:

$$\text{Calculated droop} = -\frac{150 * -0.2}{60 * 8} = 0.0625 \text{ or } 6.25\%$$

GENERATION RESOURCE FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters): ______________________ Location (County): ________________

Unit Name: ___________________________________ Date of Test: ______________________

QSE: ____ Resource Entity: __________________

TEST RESULTS

		Test with +0.2 Hz	**Test with -0.2 Hz**
1	**Generation Resource Base Load**		
2	**GAIN MW to 0.1Hz**		
3	**Calculated MW Contribution**		
4	**MW at test start (t_0)**		
5	**MW at t_0 + 16 sec**		
6	**MW Contribution at t_0 + 16 sec**		
7	**MW at t_0 + 46 sec**		
8	**Calculated droop**		
9	**CONCLUSION (PASSED/FAILED)**		

Comments:

____

____

SUBMITTAL

Resource Entity Representative: ____

QSE Representative: ____

Date submitted to ERCOT Representative: __________________________________

ENERGY STORAGE RESOURCE FREQUENCY RESPONSE TEST PROCEDURE

DESCRIPTION OF THE TEST

1. An Energy Storage Resource (ESR) is tested On-Line in both maximum charging and discharging modes at a level that allows the ESR to increase or decrease Load without reaching its operating limits. If the ESR cannot be tested On-Line then it will notify ERCOT that it will be conducting an Off-Line test.

2. The test is performed by adding a frequency offset signal that exceeds the Governor Dead-Band value to the measured frequency signal. This should create an immediate step-change in the measured frequency signal.

3. The test starts at time t0 when the frequency dead-band is exceeded.

4. The following signals should be recorded for at least two seconds: unit MW level and frequency offset signal.

5. The duration of the test is 100 seconds. After 100 seconds, the offset signal should be removed and the Energy Storage Resource should return to the pretest MW level.

6. The test should be conducted with both positive and negative frequency offsets.

7. The test is considered successful after the signal becomes active if at least 70% of the calculated MW contribution is delivered within 16 seconds and the response is maintained for an additional 30 seconds.

8. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7, Turbine Speed Governors.

DEFINITIONS

Energy Storage Resource Base Load = MDRR for low frequency test and for high frequency test

Gain MW for 0.1Hz = $\dfrac{P}{(Droop * 60 - GovernorDead - Band) * 10}$

Where:

P = Energy Storage Resource Base Load (MW)

$Droop$ = droop (%)

Frequency Offset = +0.2 Hz and -0.2 Hz (+12 rpm and -12 rpm, for 3600 sync speed machines), outside Governor Dead-Band

Test frequency = Measured Frequency + Frequency Offset

MW Contribution = Gain MW to 0.1 Hz *10*Frequency Offset

Calculated droop = - $\dfrac{P * \Delta Hz}{60 * \Delta MW}$

Where:

P = Energy Storage Resource Base Load (MW)

ΔHz = Change in frequency (Hz), taking into account Governor Dead-Band

ΔMW = Change in power level (MW)

EXAMPLE

Energy Storage Resource Base Load = 150 MW, when discharging

Droop = 0.05 or 5% (use 0.05 for calculation)

Governor Dead-Band = 0.017

Gain MW to 0.1 Hz = $\dfrac{150}{[(0.05*60)-0.017]*10}$ = +/- 5.03 MW/0.1 Hz

MW Contribution (injection) = 5.03*10*+/- (0.2) = +/-10.06 MW

Expected under-frequency response (injection): +10.06 MW in 16 sec. for -0.2 Hz offset

Expected over-frequency response (withdrawal): -10.06 MW in 16 sec. for +0.2 Hz offset

Minimum accepted under-frequency response (injection): +7.04 MW in 15 sec. for -0.2 Hz offset
Minimum accepted over-frequency response (withdrawal): -7.04 MW in 15 sec. for +0.2 Hz offset

Calculated droop for 8 MW increase in power output in 16 sec. for -0.2 Hz offset:

Calculated droop = $-\dfrac{150 * -0.2}{60 * 8}$ = 0.0625 or 6.25%

ENERGY STORAGE RESOURCE FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters): ______________________ Location (County): _______________

Unit Name: ___________________________________ Date of Test: ____________________

QSE: ____ Resource Entity: _________________

TEST RESULTS

		Test with +0.2 Hz	Test with -0.2 Hz
1	**Energy Storage Resource (ESR) Base Load**		
2	**GAIN MW to 0.1Hz**		
3	**Calculated MW Contribution**		
4	**MW at test start (t_0)**		
5	**MW at t_0 + 16 sec**		
6	**MW Contribution at t_0 + 16 sec**		
7	**MW at t_0 + 46 sec**		
8	**Calculated droop**		
9	**CONCLUSION (PASSED/FAILED)**		

Comments:

____

____

____

SUBMITTAL

Resource Entity Representative: ______________________________________

QSE Representative: ____

Date submitted to ERCOT Representative: _______________________________

GENERATION RESOURCE, ENERGY STORAGE RESOURCE, AND CONTROLLABLE LOAD RESOURCE PRIMARY FREQUENCY RESPONSE TEST PROCEDURES BASED ON HISTORICAL DATA

DESCRIPTION OF HISTORICAL VERIFICATION

The purpose of this template is to allow the Entity that operates a Generation Resource, Energy Storage Resource (ESR) or a Controllable Load Resource (CLR) to demonstrate acceptable frequency response of its Generation Resource(s), ESR(s) or CLR(s) based on historical data in order to minimize testing costs, scheduling conflicts and the risk of damage to equipment or Forced Outage.

1. All verifications will be based on at least one of the events from the published list of Frequency Measurable Events (FMEs).

2. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7, Turbine Speed Governors.

3. For clarification purposes, the time of FME (t(0)), pre-perturbation average frequency and post-perturbation average frequency, as defined in Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response, will be used for the verification process. The values of these metrics will be identified in the FME Report.

4. The test is considered successful if the Generation Resource, ESR, or the CLR is able to meet a minimum of 75% of its initial Primary Frequency Response and 75% of its sustained Primary Frequency Response as calculated in the FMEs report posted on the Market Information System (MIS) Certified Area. Any Generation Resource, ESR, or CLR may use the FME report in lieu of testing.

a. The calculation of Generation Resources, ESRs, or CLRs initial and sustained Primary Frequency Response is detailed in Section 8, Attachment J.

b. ERCOT shall evaluate initial and sustained Primary Frequency Response using an expected performance Governor droop of 5.78% for combined-cycle Resources.

5. Intermittent Renewable Resources (IRRs) located behind one Point of Interconnection (POI), metered by one ERCOT-Polled Settlement (EPS) Meter, and operated as an integrated Facility may combine IRRs for the purposes of this test.

DEFINITIONS

Generation Resource, ESR, or CLR Base Load = MDRR (this value is not reduced for temporary output limitations of the Generation Resource, ESR, or CLR due to auxiliary equipment outages, weather conditions, or fuel limitations, it is the "nameplate" rating of the Generation Resource, ESR, or CLR). For the IRR, the Base Load for purposes of this test shall be their MDRR. The IRR shall use only a FME in which the IRR's HSL is greater than 50% of the IRR's total design output capability.

HISTORICAL GENERATION RESOURCE, ENERGY STORAGE RESOURCE, OR CONTROLLABLE LOAD RESOURCE FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters):	Location (County):
Unit Name:	Date of FME:
QSE:	Resource Entity:

HISTORICAL RESULTS

EVALUATION POINT	***FREQUENCY***
TIME (SEC) OF FME (T(0))	
PRE-PERTURBATION AVERAGE FREQUENCY (T(-2) TO T(-16))	
POST-PERTURBATION AVERAGE FREQUENCY (T(20) TO T(52))	

1	**Pre-Perturbation Average MW [T(-2) to T(-16)]**	
2	**Post-Perturbation Average MW [T(+20 to T(+52)]**	
3	**Expected Initial Primary Frequency Response (MW)**	
4	**Expected Sustained Primary Frequency Response (MW)**	
5	**Adjusted Actual Initial Primary Frequency Response (MW)**	
6	**Adjusted Actual Sustained Primary Frequency Response (MW)**	
7	**Initial Response P.U. Performance**	
8	**Sustained Response P.U. Performance**	

Comments:

____

____

____

SUBMITTAL

Resource Entity Representative: ____

QSE Representative: ____

Date submitted to ERCOT Representative: ______________________________

INTERMITTENT RENEWABLE RESOURCE (IRR) FREQUENCY RESPONSE TEST PROCEDURE

DESCRIPTION OF THE TEST

1. The frequency response function of the Intermittent Renewable Resource (IRR) is tested On-Line at a Load level that allows the IRRs to increase or decrease Load without reaching low operating limits or high operating limits.

2. The test is performed by adding a frequency offset signal that exceeds the Governor Dead-Band value to the measured frequency signal. This should create immediate step change in the measured frequency signal.

3. The test starts at time t0 when the frequency Dead-Band is exceeded.

4. The MW output signal should be recorded at least every two seconds.

5. The duration of the test is 100 seconds. After 100 seconds, the offset signal should be removed and the IRR should return to pretest power output.

6. The test should be conducted both with positive and negative frequency offsets.

7. The test is considered successful after the signal becomes active if at least 70% of the calculated MW contribution is delivered within 16 seconds and the response is maintained for an additional 30 seconds.

8. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7, Turbine Speed Governors.

9. IRRs located behind one POI, metered by one ERCOT-Polled Settlement (EPS) Meter, and operated as an integrated Facility may combine IRRs for the purposes of this test.

DEFINITIONS

IRR Base Load = MDRR. The test shall be performed at an output level which is greater than 50% of IRR's total design output capability.

Gain MW for 0.1Hz consistent with a selected droop percentage =

$$\frac{P * 10}{Droop * 60 - GovernorDead - Band}$$

Where:

P = IRR telemetered HSL (MW)

$Droop$ = droop (%)

Frequency Offset = +0.2 Hz and -0.2 Hz, outside Governor Dead-Band

Test frequency = Measured Frequency + Frequency Offset

MW Contribution = Gain MW to 0.1 Hz * 10 * Frequency Offset

Calculated droop = - $\frac{P * \Delta Hz}{60 * \Delta MW}$

Where:

P = IRR telemetered HSL (MW)

ΔHz = Change in frequency (Hz), taking into account Governor Dead-Band

ΔMW = Change in power output (MW)

EXAMPLE

IRR telemetered HSL = 150 MW

Droop = 0.05 or 5% (use 0.05 for calculation)

Governor Dead-Band = 0.017 Hz

Gain MW for 0.1 Hz = $\frac{150}{[(0.05*60)-0.017]*10}$ = +/- 5.03 MW/0.1 Hz

ΔMW Contribution = 5.03 * 10* +/-0.2 = +/-10.06 MW

Expected under-frequency response: +10.06 MW in 16 sec. for -0.2 Hz offset
Expected over-frequency response: -10.06 MW in 16 sec. for +0.2 Hz offset

Minimum accepted under-frequency response: +7.04 MW in 16 sec. for -0.2 Hz offset
Minimum accepted over-frequency response: -7.04 MW in 16 sec. for +0.2 Hz offset

Calculated droop for 8MW increase in power output in 16 sec. for -0.2 Hz offset:

Calculated percent droop = $-\frac{150*-0.2}{60*8}$ *100 = 6.25%

INTERMITTENT RENEWABLE RESOURCE (IRR) FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters): ____________________ Location (County): ______________

Unit Name: _________________________________ Date of Test: ___________________

QSE: _____________________________________ Resource Entity: ________________

TEST RESULTS

		Test with +0.2 Hz	Test with -0.2 Hz
1	IRR Base Load		
2	GAIN MW to 0.1Hz		
3	Calculated Minimum MW Contribution		
4	MW at test start (t_0)		
5	MW at t_0 + 16 sec		
6	MW Contribution at t_0 + 16 sec		
7	MW at t_0 + 46 sec		
8	Calculated droop		
9	CONCLUSION (PASSED/FAILED)		

Comments:

____

____

____

SUBMITTAL

Resource Entity Representative: ____

QSE Representative: ____

Date submitted to ERCOT Control Area Authority Rep.: ___________________________

CONTROLLABLE LOAD RESOURCE FREQUENCY RESPONSE TEST PROCEDURE

DESCRIPTION OF THE TEST

1. The frequency response function of the Controllable Load Resource (CLR) is tested On-Line at a Load level that allows CLRs to increase or decrease Load without reaching Low Power Consumption (LPC) or Maximum Power Consumption (MPC).

2. The test is performed by adding a frequency offset signal that exceeds the Governor Dead-Band value to the measured frequency signal. This should create an immediate step change in the measured frequency signal.

3. The test starts at time t0 when the frequency Dead-Band is exceeded.

4. The MW output signal should be recorded at least every two seconds.

5. The duration of the test is 100 seconds. After 100 seconds, the offset signal should be removed and the CLR should return to pretest power output.

6. The test should be conducted both with positive and negative frequency offsets.

7. The test is considered successful after the signal becomes active if at least 70% of the calculated MW contribution is delivered within 16 seconds and the response is maintained for an additional 30 seconds.

8. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7, Turbine Speed Governors.

DEFINITIONS

Controllable Load Resource Base Load = MDRR. The test shall be performed at an output level that allows the CLR to increase or decrease Load without reaching LPC or MPC.

Gain MW for 0.1Hz consistent with a selected droop percentage =

$$\frac{P}{(Droop * 60 - GovernorDead - Band) * 10}$$

Where:

P = CLR telemetered MPC (MW)

$Droop$ = droop (%)

Frequency Offset = +0.2 Hz and -0.2 Hz, outside Governor Dead-Band

Test frequency = Measured Frequency + Frequency Offset

MW Contribution = Gain MW to 0.1 Hz * 10 * Frequency Offset

Calculated droop = - $\frac{P * \Delta Hz}{60 * \Delta MW}$

Where:

P = CLR telemetered MPC

ΔHz = Change in frequency (Hz), taking into account Governor Dead-Band

ΔMW = Change in power output (MW)

EXAMPLE

CLR telemetered MPC = 150 MW

Droop = 5%

Governor Dead-Band = 0.036 Hz

Gain MW to 0.1 Hz = $\frac{150}{[(0.05*60)-0.036]*10}$ = +/- 5.06 MW/0.1 Hz

ΔMW Contribution = 5 * 10* +/-0.2 = +/-10.12 MW

Expected under-frequency response: -10.12 MW in 16 sec. for -0.2 Hz offset
Expected over-frequency response: +10.12 MW in 16 sec. for +0.2 Hz offset

Minimum accepted under-frequency response: -7.08 MW in 16 sec. for -0.2 Hz offset
Minimum accepted over-frequency response: +7.08 MW in 16 sec. for +0.2 Hz offset

Note: The negative sign in expected under-frequency response and minimum accepted under-frequency response denotes the required reduction in power consumption. Similarly the positive sign in expected over-frequency response and minimum accepted over-frequency response denotes the required increase in power consumption.

Calculated droop for 8 MW increase in power output in 16 sec. for -0.2 Hz offset:

Calculated percent droop = $-\frac{150*-0.2}{60*8}$ = 6.25%

CONTROLLABLE LOAD RESOURCE FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters): ____________________ Location (County): ______________

Unit Name: ________________________________ Date of Test: ____________________

QSE: _____________________________________ Resource Entity: ________________

TEST RESULTS

		Test with +0.2 Hz	Test with -0.2 Hz
1	**CLR Base Load**		
2	**GAIN MW to 0.1 Hz**		
3	**Calculated Minimum MW Contribution**		
4	**MW at test start (t_0)**		
5	**MW at t_0 + 16 sec**		
6	**MW Contribution at t_0 + 16 sec**		
7	**MW at t_0 + 46 sec**		
8	**Calculated droop**		
9	**CONCLUSION (PASSED/FAILED)**		

Comments:

____

____

____

SUBMITTAL

Resource Entity Representative: ______________________________________

QSE Representative: ____

Date submitted to ERCOT Control Area Authority Rep.: ________________________

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Seasonal Unit Net Real Power Capability Verification

February 1, 2022

SEASONAL UNIT NET REAL POWER CAPABILITY VERIFICATION

GENERAL INFORMATION

Unit Code (16 character): _______________ Location (County): ____________________

Unit Name: __________________________ Date of test: __________________________

Generator's QSE: _____________________ Resource Entity: ______________________

TEST RESULTS

Start Time: ____

Start MW (Gross)*: ____

Start MW (Net)**: ____

MW 10 Minutes after Start Time (Gross)*: ______________________________________

MW 10 Minutes after Start Time (Net)**: _______________________________________

Time to Reach Maximum Generation: ____

Temperature at Plant (°F): ____

MW at Maximum Generation (Gross)*: ____

MW at Maximum Generation (Net)**: ____

MWH Net during the First Full Clock Hour after Maximum Generation is reached: _____
____

Limiting Factors: ____
____

* Value measured at generator terminals
** Value measured at the Point of Interconnection Bus (POIB)

SUBMITTAL

Resource Entity Representative: ____

QSE Representative: ____

Date submitted to ERCOT Rep.: ____

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Black Start Plan Template

October 4, 2013

This attachment provides a template to be used by each Transmission Operator (TO) for the development of their Black Start plans. As required by paragraph (2)(a) of Section 4.6.4, Responsibilities, all TOs are required to submit their Black Start plan to ERCOT.

BLACK START PLAN TEMPLATE

I. PURPOSE – The purpose statement will address the intended outcome of the TOs Black Start plan.

II. SCOPE – The scope statement shall provide, in a brief summary, the boundaries of the Black Start plan and to whom the Black Start plan applies.

III. DEFINITIONS – Definitions of terms that are used in the TO Black Start plan that are not common to the ERCOT Region.

IV. KEY PERSONNEL ROLES AND RESPONSIBILITIES – Identify roles and responsibilities of key personnel in case of a Partial Blackout or Blackout.

  A. System Operations – Personnel responsible for coordinating in emergency and system restoration.

  B. Generation Resources – Personnel responsible for the operation of Black Start Resource(s).

  C. Resource Control (Qualified Scheduling Entities (QSEs)) – Personnel responsible for acting as the QSE for Generation Resources.

V. CONTACT INFORMATION – (Identify key personnel and contact information)

  A. ERCOT

  B. ERCOT contracted Black Start Resources

  C. Non-contracted Generation Resources – include Available Generation Resources, Next Start Resources and Co-Generation/Private Use Networks, as applicable.

  D. Interconnecting TOs

  E. Resource Control (QSEs) System Operations

  F. Internal contacts (i.e., chief system operator, directors, managers)

VI. STRATEGIES – Strategies for restoration that are coordinated with ERCOT's high level strategy for restoring the ERCOT System.

A. Cranking Paths – Primary and, if applicable, secondary Cranking Paths from a Black Start Resource to the designated next start Resource.

B. Primary Synchronization Corridors – Primary Synchronization Corridor to the synchronization point(s).

C. Secondary Synchronization Corridors – Secondary Synchronization Corridor to the synchronization point(s).

D. Synchronization procedures – Operating processes to reestablish connections within the TO's system for areas that have been restored and are prepared for reconnection and procedures for restoring interconnections with other TOs under the direction of ERCOT including location, ownership, and special requirements of each synchronization point.

E. Operating processes for transferring authority back to ERCOT in accordance with ERCOT's criteria.

VII. PRIORITIES

A. Identifying the Partial Blackout or Blackout event – Clearly state how a Partial Blackout or Blackout event will be recognized.

B. Transferring control away from ERCOT – Acknowledge that, in the event of a partial Blackout or Blackout, the TO will have ERCOT's authority to bring Generation Resources On-Line and serve Load. The TO should note that it may not be possible for ERCOT to communicate this transfer of authority and that the transfer can be assumed once a Partial Blackout or Blackout condition has been identified.

C. Verification of condition of Black Start Resources – Communications in place to contact Black Start Resources.

D. Maintain acceptable operating voltage and frequency limits during restoration – List acceptable operating voltage and frequency limits during restoration.

E. Verification of tie line status – List of tie lines and owners.

F. Procedures for off-site power requirements of nuclear power plants, including priority of restoration.

G. Provide off-site power to additional Generation Resources.

H. Provide service to key facilities – List key facilities identified by the TO such as essential public services, fuel sources, and military facilities.

I. Building stable Island(s) – Primarily focus on building stable Islands with the ultimate goal of reaching synchronization points. TO Black Start plans should also consider that while larger Islands are more stable, they might be more difficult to synchronize with neighboring Islands. The TO's Black Start plan should contain instructions for adding Load and Generation Resources within the Island.

J. Reaching synchronization points – Focus on restoring the ERCOT System and not restoring service to Customers. The primary focus of the TO Black Start plan should be on building a stable Island that reaches a designated synchronization point.

K. Synchronizing Islands – TOs shall contact ERCOT when Islands are ready to be synchronized. Actual synchronization will occur with TOs communicating directly with each other. ERCOT will coordinate frequency control.

L. Restoring Load after synchronization – Note that after synchronization occurs between Islands, ERCOT will direct the further addition of Load and Generation Resources. The TO will continue to add Load and Generation Resources at the direction of ERCOT as specified in Section VI, Strategies, of this plan.

VIII. OPERATIONS – The TO Black Start plan should address at least the following items and include a subsection for operations of each Island.

A. Generation:

i. System Status Verification – The process a Black Start Resource operator would use to determine status of the transmission system.

ii. ERCOT contracted Black Start Resources:

1. Name/Location

2. Characteristics including, but not limited to the following: MW and MVAr capacity, and type of unit.

3. Fuel source and alternate fuel source

4. Fuel switching

5. Startup characteristics

6. Load Pick-up procedures

iii. Non-contracted Generation Resources

1. Available Generation Resources
    a. Name/location
    b. Characteristics
    c. Restoration of station service
    d. Fuel source(s)
    e. Fuel switching
    f. Startup characteristics
    g. Load pick-up procedures
2. Next Start Resources
    a. Name/location
    b. Characteristics
    c. Fuel source(s)
    d. Fuel switching
    e. Startup characteristics
    f. Load pick-up procedures
3. Co-generation / Private Use Networks
    a. Name/location
    b. Characteristics
    c. Restoration of station service
    d. Fuel source(s)
    e. Fuel switching
    f. Startup characteristics
    g. Load pick-up procedures

B. Transmission

i. System Status Verification – The process a TO would use to determine system status.

1. Verification of condition of Black Start Resources

2. Verification of tie line status

ii. Black Start Corridors

1. Switching Guidelines – Operating processes to restore Loads required to restore the ERCOT System, such as station service for substations, Resources to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.

a. Cranking Paths – Switching guidelines for Cranking Paths from a Black Start Resource to the designated next start Resource including a one-line diagram.

b. Primary Synchronization Corridors – Switching guidelines for primary Synchronization Corridor include a one-line diagram.

c. Secondary Synchronization Corridors – Switching guidelines for secondary Synchronization Corridor including a one-line diagram.

iii. Breakers with Synchronization Capability

1. Location and ownership of each synchronization point.

2. Synchronization procedures and special requirements for each location.

iv. Transmission Line Considerations – Special considerations given for system equipment that falls outside the normal mode of operation.

v. Relay Action Considerations

vi. Load Restoration

1. Priorities (key Loads)

2. Loads requiring system voltage and frequency consideration

C. Local Control Center

i. Telecommunications system

1. Overview

2. Failure of critical communications

ii. Power Supply

1. Overview

2. Failure of power supply

D. Contingency Plan

i. Failure of contracted Black Start Resources to start

ii. Loss of primary and secondary Synchronization Corridors

1. Coordinate with ERCOT

2. Coordinate with neighboring local control center

3. Identify alternative synchronization points

4. Use the best available transmission corridors

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Seasonal Generation Resource Operating in Synchronous Condenser Fast-Response Mode Responsive Reserve Net Capability Verification

March 1, 2020

Seasonal Generation Resource Operating in Synchronous Condenser Fast-Response Mode Responsive Reserve Net Capability Verification

GENERAL INFORMATION

Unit Code (16 character): ________________ Location (County): ______________________

Unit Name: ____________________________ Date of test: ___________________________

Generator's QSE: ______________________ Resource Entity: _______________________

TEST DETAILS

Start Time ______________________

Start MW _______________________

MW at 20 seconds _______________

Max MW _______________________

SUBMITTAL

Resource Entity Representative: ____

QSE Representative: ____

Date submitted to ERCOT Rep.: _____________________________

ERCOT Nodal Operating Guides
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Attachment G

Load Resource Tests

June 9, 2023

Annual Load Resource Telemetry Test

GENERAL INFORMATION

Date:__________________________Location (County):___________________________

ERCOT Asset Code:_____________Load Resource's QSE:________________________

Load Resource Name:____________Load Point Name:____________________________
(multiple points only)

FOR TEST DETAILS REFERENCE SECTION 3.4, LOAD RESOURCE TESTING REQUIREMENT.

TELEMETRY TEST RESULTS

Start Time Interval:____

Load Resource Breaker Status:__________________Response MW:__________________

UFR Status*:____________________MW at Maximum Load**:_____________________

Note: * Only applicable to Load Resources providing Responsive Reserve (RRS) or ERCOT Contingency Reserve Service (ECRS)
** Maximum available capacity for each Load Resources will be capped to the Maximum Load test level

By signature below, the Load Resource Representative certifies that the telemetry and high set under frequency relays, where applicable, are in place and fully functional.

SUBMITTAL

Load Resource Representative Name:____

Signature:____

QSE Representative:____________________Date submitted to ERCOT:_______________

ERCOT Validation By:__________________Date:_________________________________

Biennial Test for Load Resources Providing Responsive Reserve Service

GENERAL INFORMATION

Date:________________________________Location (County):_____________________

ERCOT Asset Code:___________________Load Resource's QSE:__________________

Load Resource Name:__________________Load Point Name:_____________________
(multiple points only)

INSTRUCTIONS

As specified in Protocol Section 8.1.1.2, General Capacity Testing Requirements, a Load Resource providing RRS Service shall test each under frequency relay or solid state controller, whichever applies, for correct operation. A separate certified relay test results sheet is to be attached for each relay tested. Please provide sufficient notation on each test sheet to assist ERCOT in matching up the sheet to individual relays. This test of the under frequency relay does not require the Load to be interrupted. If, within the biennial testing period, the Load's performance has been verified through the correct response to an actual event, the data from that event can be supplied to meet this requirement and the required annual telemetry test. The date, interval, and other information associated with the event are to be noted below. ERCOT will return a copy of the validated test form to the QSE.

VERIFICATION OF TELEMETERED RESPONSE TO AN ACTUAL EVENT

Date of event:_________________________Interval of event:______________________________

Load Resource Breaker Status:________________________MW Load Prior to Event:__________

UFR Status:________Instantaneous Response MW:______Frequency deviation Hz:___________

Time Load restored:________ERCOT Operator:____

SUBMITTAL

By signature below the Load Resource representative certifies the high set under frequency relay(s) are in place and fully functional.

Load Resource Representative Name:____

Signature:____

Name of Company Performing Relay Test:____

QSE Representative:___________________Date submitted to ERCOT:_____________________

ERCOT Validation By:________________________Date:__________________________________

Note: Please attach certified relay test results sheet(s) to this form when submitting to ERCOT.

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Unit Alternative Fuel Capability

December 1, 2010

MARKET PARTICIPANT - PROTECTED INFORMATION

THIS INFORMATION IS PROTECTED INFORMATION PURSUANT TO PROTOCOL SECTION 1.3.1.1(y), ITEMS CONSIDERED PROTECTED INFORMATION AND CONTAINS CONFIDENTIAL/PROPRIETARY INFORMATION OF THE MARKET PARTICIPANT.
THIS INFORMATION MUST BE KEPT STRICTLY CONFIDENTIAL AND IS PROVIDED TO ERCOT EMPLOYEES ONLY ON A"NEED TO KNOW" BASIS AND WILL NOT BE SHARED WITH ANYONE OUTSIDE ERCOT.

General Information						
Unit Code	Primary Fuel[1]	Alternative Fuel[1]	Alt Source - Pipeline, Truck, etc…	Date of Last MW Curtailment on Primary Fuel	MW Curtailed	Reason for Curtailment/Comments

[1]Indicate one of the following Fuel Types:

BITUMINOUS COAL	BUTANE	COAL PROCESSES	COKE-EVEN COAL	DIESEL	JET FUEL
LANDFILL GAS	LIGNITE	METHANOL	NATURAL GAS	NO 1 FUEL OIL	NO 2 FUEL OIL
NO 4 FUEL OIL	NO 5 FUEL OIL	NO 6 FUEL OIL	NUCLEAR	PETROLEUM COKE	PROPANE
PURCHASED STEAM WATER-CONVENTIONAL		PURCHASED STEAM WATER-PUMPED STORAGE		REFINERY GAS	SUB-BITUMINOUS COAL
WIND					

MARKET PARTICIPANT - PROTECTED INFORMATION

THIS INFORMATION IS PROTECTED INFORMATION PURSUANT TO PROTOCOL SECTION 1.3.1.1(x), ITEMS CONSIDERED PROTECTED INFORMATION AND CONTAINS CONFIDENTIAL/PROPRIETARY INFORMATION OF THE MARKET PARTICIPANT.
THIS INFORMATION MUST BE KEPT STRICTLY CONFIDENTIAL AND IS PROVIDED TO ERCOT EMPLOYEES ONLY ON A"NEED TO KNOW" BASIS AND WILL NOT BE SHARED WITH ANYONE OUTSIDE ERCOT.

Alternative Fuel					
Unit Code	Capable of using 100% Alternative Fuel – (Yes/No)	Maximum % Alternative Blend	No. Hours to Transition to Alternative Fuel	No. Hours @ HSL using Alternative Fuel	Comments

MARKET PARTICIPANT - PROTECTED INFORMATION

THIS INFORMATION IS PROTECTED INFORMATION PURSUANT TO PROTOCOL SECTION 1.3.1.1(x), ITEMS CONSIDERED PROTECTED INFORMATION AND CONTAINS CONFIDENTIAL/PROPRIETARY INFORMATION OF THE MARKET PARTICIPANT.
THIS INFORMATION MUST BE KEPT STRICTLY CONFIDENTIAL AND IS PROVIDED TO ERCOT EMPLOYEES ONLY ON A"NEED TO KNOW" BASIS AND WILL NOT BE SHARED WITH ANYONE OUTSIDE ERCOT.

Natural Gas Fuel								
Column 1	*Column 2*	*Column 3*	*Column 4*	*Column 5*	*Column 6*	*Col 7*	*Col 8*	*Column 9*
Unit Code	**Planned Average MWh/day (firm+ nonfirm gas)**	**Average MWh/day firm gas only**	**Maximum MW instantaneous firm + non-firm gas**	**Maximum MW instantaneous firm gas only**	**Date Range - (e.g. Nov. 07 - 14)**	**Delivery (Excluding Force Majeure)**		**Comments**
						Firm%	**Non Firm%**	

Note: See example on the following page.
In column 2 enter the sum of MWh projected to run over the day, divided by 24
In column 3, enter the sum of MWh projected to run over the day supported by FIRM GAS only, divided by 24
In column 4, enter the maximum MW projected to run instantaneously
In column 5, enter the maximum MW projected to run instantaneously that can be supported by FIRM gas and firm delivery
In column 6, enter the date range this data covers. If it changes, provide multiple date range entries for each unique occurrence.
In column 7, enter the column 3 entry divided by the column 2 entry.
In column 8, enter the column 2 entry, minus the column 3 entry, divided by the column 2 entry (2-3)/2

Natural Gas Fuel								
Column 1	*Column 2*	*Column 3*	*Column 4*	*Column 5*	*Column 6*	*Col 7*	*Col 8*	*Column 9*
Unit Code	**Planned Average MWh/day (firm+ nonfirm gas)**	**Average MWh/day firm gas only**	**Maximum MW instantaneous firm + non-firm gas**	**Maximum MW instantaneous firm gas only**	**Date Range - (e.g. Nov. 07 - 14)**	**Delivery (Excluding Force Majeure)**		**Comments**
						Firm%	**Non Firm%**	
Unit A	*2*	*0*	*100*	*0*	*December 7-9*	*0%*	*100%*	
Unit B	*290*	*0*	*600*	*0*	*December 7-9*		*100%*	
Unit C	*0*	*0*	*0*	*0*	*December 7-9*	*0*	*0*	*Available but not planned on*
Unit D	*79*	*40*	*650*	*100*	*December 7-9*	*51%*	*49%*	
Unit E					*December 7-9*			*Forced off until December 15*
Unit F	*33*	*33*	*190*	*0*	*December 7-9*	*100%*	*0%*	
Unit G	*0*	*0*	*0*	*0*	*December 7-9*			

Note: The form is filled out with examples to help clarify.
In column 2 enter the sum of MWh projected to run over the day, divided by 24
In column 3, enter the sum of MWh projected to run over the day supported by FIRM GAS only, divided by 24
In column 4, enter the maximum MW projected to run instantaneously
In column 5, enter the maximum MW projected to run instantaneously that can be supported by FIRM gas and firm delivery
In column 6, enter the date range this data covers. If it changes, provide multiple date range entries for each unique occurrence.
In column 7, enter the column 3 entry divided by the column 2 entry.
In column 8, enter the column 2 entry, minus the column 3 entry, divided by the column 2 entry (2-3)/2

ERCOT Nodal Operating Guides
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Attachment I

Black Start Resource Availability Test Form

October 1, 2012

BLACK START RESOURCE AVAILABILITY TEST FORM

As required by Protocol Section 8.1.1.2.1.5, System Black Start Capability and Testing, Black Start Resources shall complete and provide this form to ERCOT on a quarterly basis.

Name of Black Start Resource: ____

Check method to satisfy quarterly Black Start Resource Availability Test:

☐ Black Start Test – Complete Part A

☐ Successful Start and Normal Operation – Complete Part B

PART A – Black Start Test

Date of Test: __________________________

Time ERCOT Notified the Qualified Scheduling Entity (QSE) of testing: ___________________

Actual Start Time: ________________________

Time Black Start Resource reached the Low Sustained Limit (LSL): ______________________

Black Start Resource LSL per the Current Operating Plan (COP): _________________________

Did the Black Start Resource operate at or above its LSL for at least four consecutive Settlement Intervals? ________

Time and Date test was completed (breaker open): _____________________________________

PART B – Successful Start and Normal Operation

Date of Successful Start: _______________________________________

Time Black Start Resource reached the LSL:

____

Black Start Resource LSL per the current COP: ___________________________

Did the Black Start Resource operate at or above its LSL for at least four consecutive Settlement Intervals? ________

Was this run time due to an Energy Emergency Alert (EEA) or Normal Operation? ___________

REQUIRED SIGNATURES

QSE Representative Name / Signature: _____________________ / ________________________

Date ___________________________

If a Black Start Availability Test was performed:

ERCOT Operator Name / Signature: ________________________ / _______________________

Date ___________________________

ERCOT Nodal Operating Guides
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Attachment J

Initial and Sustained Measurements for Primary Frequency Response

December 1, 2024

INITIAL PRIMARY FREQUENCY RESPONSE PERFORMANCE CALCULATION METHODOLOGY

This section establishes the process used to calculate initial Primary Frequency Response (PFR) performance for each Frequency Measurable Event (FME) for Generation Resources, Energy Storage Resources (ESRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), and Controllable Load Resources.

This process calculates the initial Per Unit PFR of a Resource ($P.U.PFR_{Resource}$) as a ratio between the Adjusted Actual PFR ($APFR_{Adj}$), adjusted for the pre-event ramping of the unit, and the Final Expected PFR ($EPFR_{final}$) as calculated using the Pre-perturbation and Post-perturbation time periods of the initial measure.

This comparison of actual performance to a calculated target value establishes, for each type of Resource, the initial $P.U.PFR_{Resource}$ for any FME.

Initial Primary Frequency Response Measurement

$P.U.PFR_{Resource}$ is the per unit measure of the initial PFR of a Resource during identified FMEs.

$$P.U.PFR_{\mathrm{Resource}} = \frac{Actual\ \mathrm{Pr}imary\ Frequency\ \mathrm{Re}sponse_{Adj}}{Expected\ \mathrm{Pr}imary\ Frequency\ \mathrm{Re}sponse_{final}}$$

Where $P.U.PFR_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The Adjusted Actual PFR ($APFR_{Adj}$) and the Final Expected PFR ($EPFR_{final}$) are calculated as described below.

EPFR calculations use Governor droop and Governor Dead-Band values as stated in Section 2.2.7, Turbine Speed Governors, with the exception of combined-cycle facilities while being evaluated as a single resource (MW production of both the combustion turbine generator and the steam turbine generator are included in the evaluation) where the evaluation Governor droop will be 5.78%

Actual Primary Frequency Response ($APFR_{adj}$)

The Adjusted Actual Primary Frequency Response ($APFR_{adj}$) is the difference between Post-perturbation Average MW and Pre-perturbation Average MW, including the ramp magnitude adjustment.

$$APFR_{adj} = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2

$$MW_{pre\ -\ perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\#\, Scans}$$

Post-perturbation Average MW: Actual MW averaged from T+20 to T+52

$$MW_{post\ -\ perturbation} = \frac{\sum_{T+20}^{T+52} MW}{\#\, Scans}$$

Ramp Adjustment: The Actual PFR number that is used to calculate $P.U.PFR_{Resource}$ is adjusted for the ramp magnitude of the generating unit/generating facility during the pre-perturbation minute. The ramp magnitude is subtracted from the APFR.

Ramp Magnitude = $(MW_{T-4} – MW_{T-60})$*0.59

$(MW_{T-4} – MW_{T-60})$ represents unit's MW ramp for a full minute prior to the FME. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

For all Generation Resources, ESRs, SOTGs, SOTSGs, and Controllable Load Resources, the ideal Expected PFR ($EPFR_{ideal}$) is calculated as the difference between the $EPFR_{post-perturbation}$ and the $EPFR_{pre-perturbation}$.

$$EPFR_{ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor Dead-Band and above 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

When the frequency is outside the Governor Dead-Band and below 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor Dead-Band the appropriate EPFR value is zero. The $deadband_{max}$ and $droop_{max}$ quantities come from Section 2.2.7, Turbine Speed Governors.

Where:

Pre-perturbation Average Hz: Actual Hz averaged from T-16 to T-2

$$Hz_{pre-perturbation} = \frac{\sum_{T-16}^{T-2} Hz}{\#\,Scans}$$

Post-perturbation Average Hz: Actual Hz averaged from T+20 to T+52

$$Hz_{post-perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\#\,Scans}$$

Power Augmentation: For combined cycle facilities, Real-Time telemetered High Sustained Limit (HSL) is adjusted by subtracting the Real-Time telemetered Non-Frequency Responsive Capacity (power augmentation (PA) capacity). Other generator types may also have power augmentation that is not frequency responsive. This could be “over-pressure” operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The Resource Entity should provide ERCOT with documentation and conditions when power augmentation is to be considered in PFR calculations as described in paragraph (11) of Protocol Section 6.5.5.2, Operational Data Requirements.

$EPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) \times 10 \times 0.00276 \times (HSL - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of capacity and represents the MW change in combustion turbine's output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.

$EPFR_{final}$ for Steam Turbine

$$EPFR_{final} = \left(EPFR_{ideal} + MW_{adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{adj} = EPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PA\ Capacity) \times Steam\ Flow\ Change\ Factor\ \times -1$$

where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The rated throttle pressure and the pressure curve, based on generator MW output, are submitted to ERCOT. This pressure curve is defined by up to six pair of pressure and MW breakpoints with the throttle pressure/MW output pair where rated throttle pressure is achieved as the first set and the throttle pressure/MW output pair where the minimum throttle pressure is achieved, as the last set of breakpoints. If fewer breakpoints are needed, the pair values will be repeated for different MW outputs (i.e., MW cannot be repeated on throttle pressure) to complete the six pair table.

The K factor is used to model the stored energy available to the Resource. The value ranges between 0.0 and 0.6 psig per MW change when responding during an FME. The Resource Entity can measure the drop in throttle pressure when the Resource is operating near 50% output of the steam turbine during an FME and provide this ratio of pressure change to ERCOT. K is then adjusted based on rated throttle pressure and Resource capacity. An additional sensitivity factor, the steam flow change factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at Resource outputs below 50% and increase the adjustment at outputs above 50%. The Resource Entity should determine the fixed K factor for each Resource that generally results in the best match between EPFR and APFR (resulting in the highest $P.U.PFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

$EPFR_{final}$ for Other Generating Units/Generating Facilities and Energy Storage Resources

$$EPFR_{final} = EPFR_{ideal} + X$$

Where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the Resource. X may be adjusted by ERCOT and may be variable across the operating range of a resource. X shall be zero unless ERCOT accepts an alternative value.

[NOGRR263: Replace Initial Primary Frequency Response Performance Calculation Methodology above with the following upon system implementation of NPRR1244:]

INITIAL PRIMARY FREQUENCY RESPONSE PERFORMANCE CALCULATION METHODOLOGY

This section establishes the process used to calculate initial Primary Frequency Response (PFR) performance for each Frequency Measurable Event (FME) for Generation Resources, Energy Storage Resources (ESRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), and Controllable Load Resources that are subject to this evaluation.

This process calculates the initial Per Unit PFR of a Resource ($P.U.PFR_{Resource}$) as a ratio between the Adjusted Actual PFR ($APFR_{Adj}$), adjusted for the pre-event ramping of the unit, and the Final Expected PFR ($EPFR_{final}$) as calculated using the Pre-perturbation and Post-perturbation time periods of the initial measure.

This comparison of actual performance to a calculated target value establishes, for each type of Resource, the initial $P.U.PFR_{Resource}$ for any FME.

Initial Primary Frequency Response Measurement

$P.U.PFR_{Resource}$ is the per unit measure of the initial PFR of a Resource during identified FMEs.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response_{Adj}}{Expected\ Primary\ Frequency\ Response_{final}}$$

Where $P.U.PFR_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The Adjusted Actual PFR ($APFR_{Adj}$) and the Final Expected PFR ($EPFR_{final}$) are calculated as described below.

EPFR calculations use Governor droop and Governor Dead-Band values as stated in Section 2.2.7, Turbine Speed Governors, with the exception of combined-cycle facilities while being evaluated as a single resource (MW production of both the combustion turbine generator and the steam turbine generator are included in the evaluation) where the evaluation Governor droop will be 5.78%

Actual Primary Frequency Response ($APFR_{adj}$)

The Adjusted Actual Primary Frequency Response ($APFR_{adj}$) is the difference between Post-perturbation Average MW and Pre-perturbation Average MW, including the ramp magnitude adjustment.

$$APFR_{adj} = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2

$$MW_{pre-perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\#\ Scans}$$

Post-perturbation Average MW: Actual MW averaged from T+20 to T+52

$$MW_{post-perturbation} = \frac{\sum_{T+20}^{T+52} MW}{\#\ Scans}$$

Ramp Adjustment: The Actual PFR number that is used to calculate $P.U.PFR_{Resource}$ is adjusted for the ramp magnitude of the generating unit/generating facility during the pre-perturbation minute. The ramp magnitude is subtracted from the APFR.

Ramp Magnitude = $(MW_{T-4} - MW_{T-60})$*0.59

$(MW_{T-4} - MW_{T-60})$ represents unit's MW ramp for a full minute prior to the FME. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

For all Generation Resources, ESRs, SOTGs, SOTSGs, and Controllable Load Resources, the ideal Expected PFR ($EPFR_{ideal}$) is calculated as the difference between the $EPFR_{post\text{-}perturbation}$ and the $EPFR_{pre\text{-}perturbation}$.

$$EPFR_{ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor Dead-Band and above 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

When the frequency is outside the Governor Dead-Band and below 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor Dead-Band the appropriate EPFR value is zero. The $deadband_{max}$ and $droop_{max}$ quantities come from Section 2.2.7, Turbine Speed Governors.

Where:

Pre-perturbation Average Hz: Actual Hz averaged from T-16 to T-2

$$Hz_{pre\ -\ perturbation} = \frac{\sum_{T-16}^{T-2} Hz}{\#\, Scans}$$

Post-perturbation Average Hz: Actual Hz averaged from T+20 to T+52

$$Hz_{post\ -\ perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\#\, Scans}$$

Power Augmentation: For combined cycle facilities, Real-Time telemetered High Sustained Limit (HSL) is adjusted by subtracting the Real-Time telemetered Non-Frequency Responsive Capacity (power augmentation (PA) capacity). Other generator types may also have power augmentation that is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The Resource Entity should provide ERCOT with documentation and conditions when power augmentation is to be considered in PFR calculations as described in paragraph (11) of Protocol Section 6.5.5.2, Operational Data Requirements.

EPFR$_{final}$ for Combustion Turbines and Combined Cycle Facilities

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) \times 10 \times 0.00276 \times (HSL - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of capacity and represents the MW change in combustion turbine's output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.

EPFR$_{final}$ for Steam Turbine

$$EPFR_{final} = \left(EPFR_{ideal} + MW_{adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{adj} = EPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PA\ Capacity) \times Steam\ Flow\ Change\ Factor\ \times -1$$

where:

$$\% \ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\% \ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The rated throttle pressure and the pressure curve, based on generator MW output, are submitted to ERCOT. This pressure curve is defined by up to six pair of pressure and MW breakpoints with the throttle pressure/MW output pair where rated throttle pressure is achieved as the first set and the throttle pressure/MW output pair where the minimum throttle pressure is achieved, as the last set of breakpoints. If fewer breakpoints are needed, the pair values will be repeated for different MW outputs (i.e., MW cannot be repeated on throttle pressure) to complete the six pair table.

The K factor is used to model the stored energy available to the Resource. The value ranges between 0.0 and 0.6 psig per MW change when responding during an FME. The Resource Entity can measure the drop in throttle pressure when the Resource is operating near 50% output of the steam turbine during an FME and provide this ratio of pressure change to ERCOT. K is then adjusted based on rated throttle pressure and Resource capacity. An additional sensitivity factor, the steam flow change factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at Resource outputs below 50% and increase the adjustment at outputs above 50%. The Resource Entity should determine the fixed K factor for each Resource that generally results in the best match between EPFR and APFR (resulting in the highest $P.U.PFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

$EPFR_{final}$ for Other Generating Units/Generating Facilities and Energy Storage Resources

$$EPFR_{final} = EPFR_{ideal} + X$$

Where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the Resource. X may be adjusted by ERCOT and may be variable across the operating range of a resource. X shall be zero unless ERCOT accepts an alternative value.

SUSTAINED PRIMARY FREQUENCY RESPONSE PERFORMANCE CALCULATION METHODOLOGY

This section establishes the process used to calculate sustained Primary Frequency Response (PFR) performance for each Frequency Measurable Event (FME).

This process calculates the Per Unit Sustained PFR of a Resource ($P.U.SPFR_{Resource}$) as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the *Final* Expected Primary Frequency Response (EPFR) value at time T+46.[1]

This comparison of actual performance to a calculated target value establishes, for each type of Resource, the $P.U.SPFR_{Resource}$ for any FME.

<u>Sustained Primary Frequency Response performance measurement:</u>

Sustained Primary Frequency Response Calculation (P.U.SPFR)

$$P.U.SPFR_{\text{Resource}} = \frac{\text{Actual Sustained Primary Frequency Response}_{Adj}}{\text{Expected Sustained Primary Frequency Response}_{final}}$$

$P.U.SPFR_{Resource}$ is the per unit (P.U.) measure of the sustained PFR of a Resource during identified FME. The $P.U.SPFR_{Resource}$ for each FME will be limited to values between 0.0 and 2.0.

<u>Actual Sustained Primary Frequency Response (ASPFR) Calculations</u>

$$ASPFR = MW_{MaximumResponse} - MW_{pre-perturbation}$$

where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2.

$$MW_{pre\ -\ perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\#\,Scans}$$

and:

[1] The time designations used in this section refer to relative time after an FME occurs. For example, "T+46" refers to 46 seconds after the frequency deviation occurred.

$MW_{MaximumResponse}$ = *maximum MW value telemetered by a unit from T+46 through T+60 during low frequency FMEs and the minimum MW value telemetered by a unit from T+46 through T+60 during a high frequency FME.*

Actual Sustained Primary Frequency Response, Adjusted ($ASPFR_{Adj}$)

$$ASPFR_{Adj} = ASPFR - RampMW\ Sustained$$

RampMW Sustained (MW) – Generation Resources, Energy Storage Resources (ESRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Generators (SOTSGs), and Controllable Load Resources are required to sustain their response to an FME. An adjustment available in determining sustained Primary Frequency Response (PFR) performance ($P.U.SPFR_{Resource}$) is to account for the direction in which a Resource was moving (increasing or decreasing output) when the FME occurred T=t(0). This is the *RampMW* Sustained adjustment:

RampMW Sustained = ($MW_{T-4} - MW_{T-60}$) x 0.821

Note: The terminology "MW_{T-4}" *refers to MW output at 4 seconds before the FME occurs at T=t(0).*

By subtracting a reading at 4 seconds before, from a reading at 60 seconds before, the formula calculates the MWs a generator moved in the minute (56 seconds) prior to T=t(0). The formula is then modified by a factor to indicate where the unit would have been at T+46, had the FME not occurred: the "*RampMW Sustained*." It does this by multiplying the MW change over 56 seconds before the event ($MW_{T-4} - MW_{T-60}$) by a modifier. This extrapolates to an equivalent number of MWs the generator would have changed if it had been allowed to continue on its ramp to T+46 unencumbered by the FME. The modifier is $\frac{46\ seconds}{56\ seconds}$ or 0.821.

<u>**Expected Sustained Primary Frequency Response (ESPFR) Calculations**</u>

The Expected Sustained Primary Frequency Response ($ESPFR_{final}$) is calculated using the actual frequency at T+46, HZT_{+46}.

This $ESPFR_{final}$ is the MW value a Generation Resource, ESR, SOTG, SOTSG, or Controllable Load Resource should have responded with, if it is properly sustaining the output of its generating unit/generating facility in response to an FME. Determination of this value begins with establishing where it would be in an ideal situation; considers proper Governor droop and Governor Dead-Band values established in Section 2.2.7, Turbine Speed Governors, High Sustained Limit (HSL), Low Sustained Limit (LSL) and actual frequency. It then allows for adjusting the value to compensate for the various types of limiting factors each Generation Resource, ESR, SOTG, SOTSG, or Controllable Load Resource may have and any Non-Frequency Responsive Capacity (NFRC) that may be included in the HSL.

Establishing the Ideal Expected Sustained Primary Frequency Response

For Generation Resources, ESRs, SOTGs, SOTSGs, and Controllable Load Resources, the ideal Expected Sustained PFR ($ESPFR_{ideal}$) is calculated as the difference between the $ESPFR_{T+46}$ and the $EPFR_{pre\text{-}perturbation}$. The $EPFR_{pre\text{-}perturbation}$ is the same $EPFR_{pre\text{-}perturbation}$ value used in the Initial measure.

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor Dead-Band and above 60Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - deadband_{\max})}{(droop_{\max} \times 60 - deadband_{\max})} \times (HSL - \text{PA Capacity}) \times (-1) \right]$$

When the frequency is outside the Governor Dead-Band and below 60Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + deadband_{\max})}{(droop_{\max} \times 60 - deadband_{\max})} \times (HSL - \text{PA Capacity}) \times (-1) \right]$$

For combined cycle facilities, determination of frequency responsive capacity includes subtracting power augmentation (PA) capacity, if any, from the original telemetered HSL. Other generator types may also have power augmentation that is not frequency responsive. This could be “over-pressure” operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The Resource Entity is required to provide ERCOT with documentation and conditions when power augmentation is to be considered in PFR calculations as described in paragraph (11) of Protocol Section 6.5.5.2, Operational Data Requirements.

$ESPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities

$$ESPFR_{final} = ESPFR_{Ideal} + (HZ_{T+46} - 60) * 10 * 0.00276 * (HSL - PACapacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of capacity and represents the MW change in combustion turbine’s output due to the change in mass flow through the combustion turbine due to the speed change of the turbine at HZT+46. (This is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

ESPFR$_{final}$ for Steam Turbine

$$ESPFR_{final} = \left(ESPFR_{ideal} + MW_{Adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{Adj} = ESPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PA\,Capacity) \times Steam\ Flow\ Change\ Factor \times (-1)$$

where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at MW$_{pre\text{-}perturbation}$

ESPFRfinal for Other Generating Units/Generating Facilities and Energy Storage Resources

$$ESPFR_{final} = ESPFR_{Ideal} + X$$

where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by ERCOT and may be variable across the operating range of a resource. X shall be zero unless ERCOT accepts an alternative value.

LIMITS ON CALCULATION OF PFR PERFORMANCE (INITIAL & SUSTAINED)

For frequency deviations below 60Hz ($HZ_{post\text{-}perturbation} < 60$)
If for a generating unit/generating facility

$$MW_{Pre-Perturbation} \geq \min([(HSL - PA\ capacity) * 0.98], [(HSL - PA\ capacity) - 5MW])$$

Then Primary Frequency Response is not evaluated for this Frequency Measurable Event (FME).
For frequency deviations above 60Hz ($HZ_{post\text{-}perturbation} > 60$)
If for a generating unit/generating facility

$$MW_{Pre-Perturbation} \leq \max([LSL + (HSL - PA\ capacity) * 0.02], [LSL + 5MW]))$$

Then Primary Frequency Response is not evaluated for this FME.

For Energy Storge Resources (ESRs), while discharging, if operating within the larger of 3 MW or 2% of the Real-Time Maximum Operating Discharge Power Limit for low frequency disturbances then Primary Frequency Response is not evaluated for this FME.

For ESRs, while charging, if operating within the larger of 3 MW or 2% of the Real-Time Maximum Operating Charge Power Limit for high frequency disturbances then Primary Frequency Response is not evaluated for this FME.

When Expected Primary Frequency Response$_{Final}$ is greater than operating margin Caps and limits exist for resources operating with adequate reserve margin to be evaluated (greater of 2% of (High Sustained Limit (HSL) less PA Capacity) or 5 MW), but with Expected Primary Frequency Response$_{Final}$ greater than the actual margin available.

(1) The $\mathrm{P.U.PFR_{Resource}}$ will be set to the greater of 0.75 or the calculated $\mathrm{P.U.PFR_{Resource}}$ if all of the following conditions are met:

(a) The generating unit/generating facility's or ESR's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its $(\mathrm{HSL} - \mathrm{PACapacity})$ and greater than 5 MW; and

(b) The $\mathrm{EPFR_{Final}}$ is greater than the generating unit/generating facility's or ESR's available frequency responsive capacity[2]; and

(c) The generating unit/generating facility's or ESR's $\mathrm{APFR_{Adj}}$ response is in the correct direction.

(2) When calculation of the $\mathrm{P.U.PFR_{Resource}}$ uses the resource's $\mathrm{HSL - PACapacity}$ as the maximum expected output, the calculated $\mathrm{P.U.PFR_{Resource}}$ will not be greater than 1.0.

(3) When calculation of the $\mathrm{P.U.PFR_{Resource}}$ uses the resource's $\mathrm{LSL - PACapacity}$ as the minimum expected output, the calculated $\mathrm{P.U.PFR_{Resource}}$ will not be greater than 1.0.

(4) If the $\mathrm{APFR_{Adj}}$is in the wrong direction, then $\mathrm{P.U.PFR_{Resource}}$ is 0.0.

(5) These caps and limits apply to both the Initial and Sustained Primary Frequency Response measures.

INITIAL PFR and SUSTAINED PFR PERFORMANCE REQUIREMENT

ERCOT computes an average Initial PFR and Sustained PFR performance based on either all FMEs evaluated within 12 months or the last eight FMEs (applicable if a minimum threshold of eight FMEs within the 12 month period is not met). Each Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), and Controllable Load Resource shall meet a minimum rolling average initial Primary Frequency Response performance and sustained Primary Frequency Response performance of 0.75.

Initial PFR requirement:

$$Avg_{Period}[P.U.PFR_{Resource}] \geq 0.75,$$

Sustained PFR requirement:

$$Avg_{Period}\,[P.U.SPFR_{Resource}] \geq 0.75$$

[2] In this circumstance, when frequency is below 60 Hz, the EPFR_final is set to operating margin based on HSL (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the EPFR_final is set to operating margin based on LSL for the purpose of calculating PUPFR_resource.

ERCOT Nodal Operating Guides
Section 8
Attachment K

Remedial Action Scheme (RAS) Template

November 1, 2023

This attachment provides a template to be used by an entity for the proposal, modification, and/or retirement of a Remedial Action Scheme (RAS). If an item in this template does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate. All submittals related to RAS must be emailed to ras_cmp@ercot.com.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The corrective action plan if RAS modifications are proposed in a corrective action plan.
4. Data to populate the RAS database:
   a. RAS name;
   b. RAS Entity and contact information;
   c. Expected or actual in-service date, most recent ERCOT approval date, most recent ERCOT evaluation date, and date of retirement;
   d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recover;
   e. Description of the contingencies or system conditions for which the RAS was designed;
   f. Action(s) to be taken by the RAS;
   g. Identification of Limited Impact RAS; and
   h. Any additional explanation relevant to high-level understanding of RAS.

II. Functional Description and Transmission Planning Information

1. Contingencies and system conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy system performance objectives for the scope of system events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), system conditions, and contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future system plans that will impact the RAS.
5. Exit Strategy that has been identified including the approved transmission project or ERCOT's recommendation to mitigate the need for the RAS. For example, reconductor Point A to Point B.
6. RAS Entity proposal and justification for Limited Impact RAS designation.

7. Documentation describing the system performance resulting from the possible inadvertent operation of the RAS, except for Limited Impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be a Limited Impact RAS must satisfy the requirements in paragraph (3)(f) of Section 11.2, Remedial Action Schemes.
8. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RASs, and protection and control systems.
9. Identification of other affected non-ERCOT Control Areas.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control applications, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or Supervisory Control and Data Acquisition (SCADA), does not compromise the reliability of the RAS when the device is not in service or is being maintained.
4. For a RAS not designated as a Limited Impact RAS, documentation describing the system performance resulting from a single component failure in the RAS, except for a Limited Impact RAS, when the RAS was intended to operate. A single component failure in a RAS not designated as a Limited Impact RAS must not prevent the bulk electric system from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

1. Information necessary to ensure that ERCOT is able to understand the physical and electrical location of the RAS and related facilities;
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based; and
3. The anticipated date of RAS retirement.

ERCOT Nodal Operating Guides
Section 8
Attachment L

Emergency Operations Plan

December 1, 2024

This attachment provides a template to be used by each Transmission Operator (TO) for the development of its emergency operations plan to mitigate operating emergencies, as required by the applicable North American Electric Reliability Corporation (NERC) Reliability Standard. The emergency operations plan can be made up of multiple parts and does not need to be a single document. When multiple parts are used, the TO shall include documentation describing the location of each element required by the applicable NERC Reliability Standard. Each plan should include each of the elements listed below:

I. PURPOSE – The purpose statement will address the TO's operations plan to mitigate operating emergencies.

II. SCOPE – The scope statement shall provide, in a brief summary, the boundaries of the emergency operations plan and to whom the emergency operations plan applies.

III. DEFINITIONS – Definitions of terms that are used in the TO emergency operations plan that are not common to the ERCOT Region. Define what is considered an operating emergency.

IV. KEY PERSONNEL ROLES AND RESPONSIBILITIES – Identify roles and responsibilities of key personnel that are responsible for activating the plan.

V. PROCESSES TO PREPARE FOR AND MITIGATE EMERGENCIES – Include the following:

A. Notification to ERCOT to include current and known projected Real-Time conditions, when experiencing an operating emergency;

B. Cancellation of Transmission Facility Outages;

C. Transmission system reconfiguration;

D. Operator-controlled manual Load shed during an Emergency Condition that accounts for each of the following:

1. Provisions for manual Load shed capable of being implemented in a timeframe adequate for mitigating the emergency;

2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for Under-Frequency Load Shed (UFLS) or Under-Voltage Load Shed (UVLS); and

4. Provisions to limit the utilization of UFLS or UVLS circuits for manual Load shed to situations where such use is consistent with the ERCOT Nodal Protocols and ERCOT Nodal Operating Guides and is warranted by system conditions.

E. Provisions to determine reliability impacts of:

1. Cold weather conditions; and

2. Extreme weather conditions.

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Section 8
Attachment M

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

August 1, 202024

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ERCOT Nodal Operating Guides
Section 8
Attachment N

Procedure for Calculating RRS MW Limits for Individual Resources to Provide RRS Using Primary Frequency Response

December 5, 2025

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1. Introduction

Changes to this attachment shall be reviewed by the Performance, Disturbance, Compliance Working Group (PDCWG).

2. Responsive Reserve Service Using Primary Frequency Response

Responsive Reserve (RRS) using Primary Frequency Response is an operating reserve on Generation Resources, Controllable Load Resources (CLRs), and Energy Storage Resources (ESRs) maintained by ERCOT to help control the frequency of the system. RRS on Resources providing Primary Frequency Response can be released to Security-Constrained Economic Dispatch (SCED) during scarcity conditions as outlined in Section 4.8, Responsive Reserve Service and ERCOT Contingency Reserve Service During Scarcity Conditions.

3. RRS MW Limits for Individual Resources

Generation Resources, ESRs, and CLRs that do not meet the 12 months or the last eight Frequency Measurable Events (FMEs) (applicable if a minimum threshold of eight FMEs within the 12 month period is not met) rolling average criteria, or have failed to score greater than or equal to 0.75 for Primary Frequency Response initial or Primary Frequency Response sustained measures (computed per Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response) for three consecutive FMEs, where the unit was evaluated, over a minimum period of two calendar months, will be subject to review of their respective RRS MW limit for Primary Frequency Response (“RRS MW Limit”) using the process outlined in Section 4 below. All other Generation Resources, ESRs, and CLRs shall continue to be limited to their respective RRS MW Limit established as follows.

1. The default RRS MW Limit for any Generation Resource, ESR, or CLR providing RRS shall be set to 20% of its Maximum Droop Response Range (MDRR). A Private Use Network with a registered Resource may use its gross High Sustained Limit (HSL) for qualifying and establishing a limit on the amount of RRS capacity that the Resources within the Private Use Network can provide.

2. RRS MW Limits for non-thermal Generation Resources, Generation Resources with a Resource Category of either (i) aeroderivative simple cycle commissioned after 1996, or (ii) Reciprocating Engines, ESRs, or CLRs may be updated to be higher or lower than the default threshold based on their droop performance characteristics and actual tests.

3. In order to ensure that the frequency responsive capability is distributed across multiple Resources, the RRS MW Limit for all Generation Resources, ESRs, or CLRs may be further adjusted based on the maximum amount of RRS that an individual Resource can provide using Primary Frequency Response established per paragraph (3) of Protocol Section 3.16, Standards for Determining Ancillary Service Quantities.

Based on Protocol Section 3.18, Resource Limits in Providing Ancillary Service, (i) Generation Resources operating in synchronous condenser fast-response mode may provide RRS up to the Generation Resource's ERCOT-validated 20-second response capability (which may be 100% of their HSL).

4. Calculating RRS MW Limits for Individual Resources

For Resources that fail the Primary Frequency Response initial or Primary Frequency Response sustained measures for three consecutive FMEs, where the unit was evaluated, over a minimum period of two calendar months or are failing the 12 months or the last eight FMEs (applicable if a minimum threshold of eight FMEs within the 12 month period is not met) rolling average criteria, ERCOT shall establish RRS MW Limit for providing RRS using Primary Frequency Response based on their respective performance during FMEs, any limitations exhibited within its dynamic models, or through droop performance tests on an as needed basis.

If the RRS MW Limit is to be determined based upon the Resource's performance during an FME, then such RRS MW Limit shall be calculated as follows,

1. The RRS MW Limit for each Generation Resource, ESR, and CLR will be calculated using the droop performance during an FME. The Calculated Droop Performance and RRS MW Limit for an FME is calculated as follows:

$$Calculated\ Droop\ Performance\ (Droop) = \frac{(MDRR - PA\ Capacity) * (\Delta Hz\ - Deadband_{max})}{ScheduledFrequency *\ \Delta MW}$$

$$Calculated\ RRS\ MW\ Limit\ (\%) = \frac{0.01 * ScheduledFrequency - Deadband_{max}}{ScheduledFrequency * Droop} * 100$$

Delta Hertz (ΔHz): The pre-perturbation [the 16-second period of time before t(0)] average frequency minus the post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency

Delta MW (ΔMW): The pre-perturbation average MW of the Resource minus the post-perturbation average MW of the Resource

Scheduled Frequency: The frequency value to be maintained on the system, always 60 Hz

Power Augmentation (PA) Capacity: The telemetered portion of a Generation Resource's HSL that represents the sustainable non-Dispatched power augmentation capability from duct firing, inlet air cooling, auxiliary boilers, or other methods which does not immediately respond, arrest, or stabilize frequency excursions during the first minutes following a disturbance without secondary frequency response or instructions from ERCOT

Deadband ($Deadband_{max}$): The range of deviations of system frequency (+/-) that produces no Primary Frequency Response

2. The median of the calculated RRS MW Limits in the last five FMEs where the unit was evaluated will be computed for each individual Generation Resource, ESR, and CLR. If a Resource hasn't participated in five FMEs, proceed to Step 3.

3. The median of all FMEs during the previous three months where the unit was evaluated will be computed for each individual Generation Resource, ESR, and CLR.

4. RRS MW Limit will be established based on the lower of the values computed in Steps 2 and 3.

If a Generation Resource's, ESR's, or CLR's performance during an FME is excluded per the current process (NERC Reliability Standard BAL-TRE-001) from the rolling average calculation, the Resource's performance will also be excluded from the RRS MW Limit calculation. Also note that all members of a Combined Cycle Generation Resource will be evaluated as one Generation Resource for the purposes of this evaluation.

5. Timeline to Establish RRS MW Limits

ERCOT will recalculate the RRS MW Limit on each individual Generation Resource, ESR, and CLR on a monthly basis. ERCOT shall post on the Market Information System (MIS) Certified area the RRS MW Limit for each Resource qualified to provide RRS by the 10^{th} day of each month. These RRS MW Limits will be effective in ERCOT systems coincident with the first Network Model Database Load[1] two months later. For example, ERCOT shall post the RRS MW Limit for each Resource by January 10, 2020. These RRS MW Limits will be effective in ERCOT systems beginning March 4, 2020. These recalculated values will follow any threshold limitations as expressed in Section 3 above.

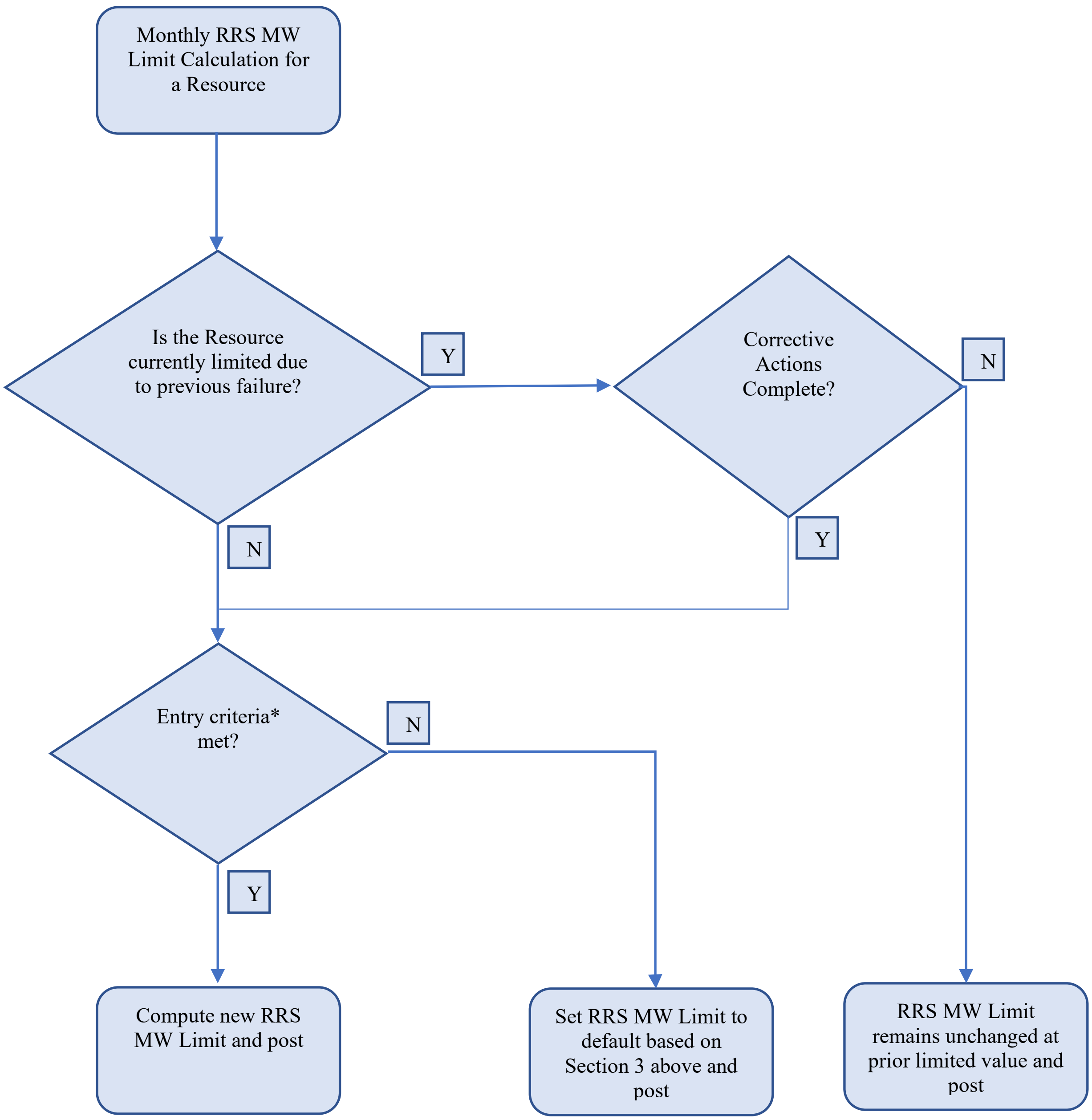
If at the time of recalculation, a Generation Resource, ESR, or CLR was previously limited due to any failure mentioned in Section 4 above, then the established RRS MW Limit will continue to apply. In order to reset the RRS MW Limit, a Generation Resource, ESR, or CLR may use dynamic models, droop performance tests, or documentation of an implemented corrective action plan to demonstrate that it is capable of carrying the standard RRS limit as mentioned in Section 3 above. A Generation Resource, ESR, or CLR that requests its RRS MW Limit to be reset must have a current 12 months or the last eight FMEs rolling average of at least 0.75 for Primary Frequency Response initial or sustained measures.

Appendix: RRS MW Limit Decision Tree

The diagram below describes at a high level the decision tree procedure to compute a RRS MW Limit for every Generation Resource, ESR, and CLR. In the event there is a conflict between the

[1] The most recent Network Model Database Load Schedules can be accessed at the following link. http://www.ercot.com/gridinfo/transmission/opsys-change-schedule.html

diagram below and text stated in the sections above, the language stated in text above takes precedence.



*(1) failed rolling average or (2) score in last three evaluated events in two consecutive months is less than 0.75

ERCOT Nodal Operating Guides

Section 9: Monitoring Programs

December 5, 2025

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9 MONITORING PROGRAMS

9.1 QSE and Resource Monitoring Program

(1) This Section sets forth formats and data needed for reporting to comply with Protocol Section 8, Performance Monitoring. These performance monitoring and compliance requirements apply as set forth below to Qualified Scheduling Entities (QSEs), Resources, Transmission Service Providers (TSPs) and ERCOT. Reports defined in this Section will be posted on the Market Information System (MIS) Secure Area unless otherwise stated.

[NOGRR177: Replace paragraph (1) above with the following upon system implementation of NPRR857:]

(1) This Section sets forth formats and data needed for reporting to comply with Protocol Section 8, Performance Monitoring. These performance monitoring and compliance requirements apply as set forth below to Qualified Scheduling Entities (QSEs), Resources, Transmission Service Providers (TSPs), Direct Current Tie Operators (DCTOs), and ERCOT. Reports defined in this Section will be posted on the Market Information System (MIS) Secure Area unless otherwise stated.

9.1.1 Real-Time Data

(1) ERCOT shall produce reports describing Real-Time data performance of QSEs in the following areas. ERCOT shall post the summary report on the MIS Secure Area.

(a) Telemetry performance:

(i) ERCOT shall produce quarterly reports describing telemetry performance as defined in the Protocols.

9.1.2 Compliance with Valid Dispatch Instructions

(1) ERCOT shall produce monthly reports detailing Resource-specific Regulation Service and energy deployment performance, including Load Resources, based on the criteria described in Protocol Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics.

(2) ERCOT shall produce a report for any system-wide deployment of Load Resources on an event basis, within 90 days after the event occurs and shall post it to the MIS Secure Area.

9.1.3 Resource Outage Reporting

(1) This Section describes the reporting of data for Resource Outage scheduling by individual Resource for informational purposes. There are no performance metrics for this data.

(2) ERCOT shall post to the MIS Certified Area, a confidential report of total number of Outages reported including Monthly Resource Outage reporting by Resource:

(a) Number of Outage requests submitted in the ERCOT Outage Scheduler greater than 335 days (11 months) in advance;

(b) Number of Outage requests submitted in the ERCOT Outage Scheduler between 90 and 334 days in advance of the desired Outage date;

(c) Number of Outage requests submitted in the ERCOT Outage Scheduler between 45 and 89 days in advance of the desired Outage date;

(d) Number of Outage requests submitted in the ERCOT Outage Scheduler between three and 44 days in advance of the desired Outage date;

(e) Number of Outage requests submitted less than three days in advance;

(f) Number of Outages by Outage type; and

(g) Total number of Outages that were requested, accepted, approved, cancelled, and withdrawn.

9.2 TSP Monitoring Program

[NOGRR177: Replace Section 9.2 above with the following upon system implementation of NPRR857:]

9.2 TSP and DCTO Monitoring Program

9.2.1 Intentionally Left Blank

9.2.2 Real-Time Data Monitor

(1) ERCOT shall produce reports describing Real-Time data performance of Transmission Service Providers (TSPs) in the following areas. ERCOT shall post the summary report on the Market Information System (MIS) Secure Area.

(a) Telemetry performance:

(i) ERCOT shall produce quarterly reports describing telemetry performance as defined in the Protocols.

[NOGRR177: Replace Section 9.2.2 above with the following upon system implementation of NPRR857:]

9.2.2 Real-Time Data Monitor

(1) ERCOT shall produce reports describing Real-Time data performance of Transmission Service Providers (TSPs) and Direct Current Tie Operators (DCTOs) in the following areas. ERCOT shall post the summary report on the Market Information System (MIS) Secure Area.

(a) Telemetry performance:

(i) ERCOT shall produce quarterly reports describing telemetry performance as defined in the Protocols.

9.2.3 Transmission Outage Reporting

(1) This Section describes the reporting data for the transmission Outage scheduling and is provided for informational purposes. There are no performance metrics for this data.

(2) ERCOT shall post a monthly report of Outages considered on the MIS Secure Area including:

(a) Number of Outage requests submitted in the ERCOT Outage Scheduler greater than 335 days (11 months) in advance;

(b) Number of Outage requests submitted in the ERCOT Outage Scheduler between 90 and 334 days in advance of the desired Outage date;

(c) Number of Outage requests submitted in the ERCOT Outage Scheduler between eight and 89 days in advance of the desired Outage date;

(d) Number of Outage requests submitted in the ERCOT Outage Scheduler between three and seven days in advance of the desired Outage date;

(e) Number of Outage requests submitted less than three days in advance;

(f) Number of Outages by Outage type; and

(g) Total Number of Outages that were requested, accepted, approved, cancelled, and withdrawn.

(3) ERCOT shall post reports for each transmission owner showing the percentage of the total number of Outages, by type, described in paragraph (2) above.

[NOGRR267: Replace paragraph (3) above with the following upon system implementation of NPRR1240:]

(3) ERCOT shall post on the ERCOT website reports for each transmission owner showing the percentage of the total number of Outages, by type, described in paragraph (2) above.

9.3 ERCOT Monitoring Program

9.3.1 Transmission Control

(1) ERCOT shall report State Estimator performance in accordance with the Protocols and post such report on the Market Information System (MIS) Secure Area.

[NOGRR267: Replace paragraph (1) above with the following upon system implementation of NPRR1240:]

(1) ERCOT shall report State Estimator performance in accordance with the Protocols and post such report on the Market Information System (MIS) Secure Area, except where otherwise stated in this paragraph (1) of Section 9.3.1.

(a) ERCOT shall produce monthly reports describing State Estimator convergence and valid State Estimator solution rates as described in Protocol Section 3.10.9.6, Telemetry and State Estimator Performance Monitoring.

[NOGRR267: Replace paragraph (a) above with the following upon system implementation of NPRR1240:]

(a) ERCOT shall post on the ERCOT website monthly reports describing State Estimator convergence and valid State Estimator solution rates as described in Protocol Section 3.10.9.6, Telemetry and State Estimator Performance Monitoring.

(b) ERCOT shall produce monthly reports describing the MW differences between State Estimator results and power flow results for identified congested Transmission Elements as approved by the Technical Advisory Committee (TAC).

(c) ERCOT shall produce monthly reports describing the MW differences between the State Estimator results and telemetry for identified congested Transmission Elements as approved by TAC.

(d) ERCOT shall produce monthly reports describing the voltage differences between the State Estimator results and telemetry for the most important voltage busses identified in accordance with the Protocols.

(e) ERCOT shall produce monthly reports describing the MW differences as defined in the Protocols.

(f) ERCOT shall produce monthly reports identifying the sum of MW flows around telemetered State Estimator Busses as described in paragraph (5) of Protocol Section 3.10.7.5.2, Continuous Telemetry of the Real-Time Measurements of Bus Load, Voltages, Tap Position, and Flows.

9.3.2 System and Resource Control

(1) The following reports shall be posted on the MIS Secure Area:

[NOGRR266: Replace paragraph (1) above with the following upon system implementation of NPRR1239:]

(1) The following reports shall be posted on the ERCOT website:

(a) Resource control metrics:

(i) Total Regulation Up Service (Reg-Up) and Regulation Down Service (Reg-Down) per interval - ERCOT shall develop a monthly report detailing the total amount of Reg-Up energy deployed in the Settlement Interval and by hour and the total amount of Reg-Down energy deployed for each Settlement Interval and by hour of the Operating Day.

(b) Reliability Unit Commitments (RUCs) and deployments:

(i) For each month, ERCOT shall report, Generation Resources committed in each RUC process, the reason for the commitment, Resource name and intervals deployed, and the hours committed for Voltage Support Service (VSS).

(c) Reversal of Base Point instructions to Generation Resources and Energy Storage Resources (ESRs) from interval to interval:

(i) ERCOT shall record and report, on a monthly basis, instances of Dispatch Instructions to Resources not providing Regulation Service in which there is a directional change in Base Point instructions for four consecutive

Security-Constrained Economic Dispatch (SCED) intervals for validation and review.

9.3.3 Computer and Communication Systems Real-Time Availability and Systems Security

(1) ERCOT shall report each month the number of times a SCED run was requested but failed to provide a valid result in less time than normal SCED interval.

9.4 Ancillary Services Monitoring Program

(1) ERCOT shall monitor Ancillary Service energy deployment according to the criteria outlined in Protocol Section 8, Performance Monitoring. Reports required by Protocol Section 8.1.1.4, Ancillary Service and Energy Deployment Compliance Criteria, will be posted on the Market Information System (MIS) Certified Area.

9.4.1 Hydro Responsive Testing

(1) ERCOT shall produce quarterly reports of hydro responsive tests and verify results submitted.

9.4.2 Resource-Specific Responsive Reserve Performance

(1) ERCOT shall develop monthly reports detailing Resource-specific Responsive Reserve (RRS) performance during deployments, including Load Resources, based on criteria described in Protocol Section 8.1.1.4.2, Responsive Reserve Service Energy Deployment Criteria.

(2) ERCOT shall publish a daily report by 0930 or as soon as practicable on the ERCOT website for the sudden loss of generation greater than 450MW and shall include:

(a) ERCOT Load at the time of each event;

(b) Time of each event;

(c) Amount of generation and Load lost contributing to the event;

(d) Approximate lowest frequency; and

(e) If there is no loss of generation, the report shall state "No Loss of generation greater than 450MW or greater."

9.4.3 Resource-Specific Non-Spinning Reserve

(1) ERCOT shall develop monthly reports detailing Resource-specific Non-Spinning Reserve (Non-Spin) performance during deployments, including Load Resources, based on the criteria described in Protocol Section 8.1.1.4.3, Non-Spinning Reserve Service Energy Deployment Criteria.

9.4.4 Resource-Specific ERCOT Contingency Reserve Service

(1) ERCOT shall develop monthly reports detailing Resource-specific ERCOT Contingency Reserve Service (ECRS) performance during deployments, including Load Resources, based on the criteria described in Protocol Section 8.1.1.4.4, ERCOT Contingency Reserve Service Energy Deployment Criteria.

ERCOT Nodal Operating Guides

Section 10: Market Data Transparency

January 1, 2021

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10 Market Data Transparency

Information in this section provides reporting transparency for operational level data. The information in this section is provided in addition to those required in the other sections of the Protocols or these Operating Guides. Pursuant to Protocol Section 12.2, ERCOT Responsibilities, ERCOT shall post information to the Market Information System (MIS) as directed throughout these Operating Guides.

10.1 Direct Current Tie Outage Information

(1) In addition to requirements in Protocol Sections 3.1.4.4, Management of Resource or Transmission Forced Outages or Maintenance Outages, and 3.1.5.1, ERCOT Evaluation of Planned Outage and Maintenance Outage of Transmission Facilities, Transmission Service Providers (TSPs) shall also enter the following information into the Outage Scheduler:

[NOGRR177: Replace paragraph (1) above with the following upon system implementation of NPRR857:]

(1) In addition to requirements in Protocol Sections 3.1.4.4, Management of Resource or Transmission Forced Outages or Maintenance Outages, and 3.1.5.1, ERCOT Evaluation of Planned Outage and Maintenance Outage of Transmission Facilities, Direct Current Tie Operators (DCTOs) shall also enter the following information into the Outage Scheduler:

(a) Specific work being performed; and

(b) If the Outage is due to work being performed on the Direct Current Tie (DC Tie) or if there is another Outage in the ERCOT Control Area which also requires an Outage on the DC Tie.

(2) As soon as practicable, ERCOT shall post the DC Tie name, start date/time, and end date/time for Forced Outages and Derates on the ERCOT website.

(3) One Business Day following the approval or cancellation of a Transmission Facility's Outage which requires a DC Tie Outage or DC Tie derate, ERCOT shall post the following information on the ERCOT website:

(a) Equipment name of impacted Transmission Facilities;

(b) Start date and time of impacted Transmission Facilities;

(c) End date and time of impacted Transmission Facilities;

(d) General description of work being performed on impacted Transmission Facilities; and

(e) If the Outage is due to work being performed on the DC Tie or if there is a transmission Outage in the ERCOT Control Area which also requires an Outage on the DC Tie.

(4) One Business Day following the approval or cancellation of a Resource Outage, which requires a DC Tie Outage or DC Tie derate, ERCOT shall post the following information on the ERCOT website:

(a) Name of impacted DC Tie;

(b) Start date and time of impacted DC Tie;

(c) End date and time of expected DC Tie Outage or DC Tie; and

(d) Explanation that the DC Tie Outage or DC Tie derate is due to a Resource Outage.

ERCOT Nodal Operating Guides

Section 11: Constraint Management Plans and Remedial Action Schemes

December 5, 2025

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11 CONSTRAINT MANAGEMENT PLANS AND REMEDIAL ACTION SCHEMES

11.1 Introduction

(1) Constraint Management Plans (CMPs) are developed in accordance to the guidelines set forth in the sections below, and are defined in Protocol Section 2.1, Definitions. CMPs include, but are not limited to the following:

(a) Remedial Action Plans (RAPs) which are modeled in Network Security Analysis (NSA) where practicable;

(b) Automatic Mitigation Plans (AMPs) which are modeled in NSA where practicable;

(c) Pre-Contingency Action Plans (PCAPs);

***[NOGRR258: Insert item (d) below upon system implementation of NPRR1198 and renumber accordingly:*]**

(d) Extended Action Plans (EAPs);

(d) Temporary Outage Action Plans (TOAPs); and

(e) Mitigation Plans.

(2) When developing CMPs, ERCOT shall first attempt to utilize the 15-Minute Rating of the impacted Transmission Facilities, where available, to develop RAPs such that the ERCOT Transmission Grid is utilized to the fullest extent.

***[NOGRR215: Insert paragraph (3) below upon system implementation and renumber accordingly:*]**

(3) Remedial Action Schemes (RASs) and/or AMPs may also be implemented in order to allow Generation Resources described in paragraph (3) of Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, to meet the minimum deliverability criteria in Planning Guide Section 4.1.1.7, or Transmission Facilities that would otherwise be subject to restrictions to operate without such restrictions.

***[NOGRR258: Insert paragraph (3) below upon system implementation of NPRR1198 and renumber accordingly:*]**

(3) EAPs may be proposed by any Market Participant or developed by ERCOT and can be

utilized for reliability or economic reasons. EAPs proposed for reliability reasons may have thermal constraints that do not have a Security-Constrained Economic Dispatch (SCED) solution. EAPs proposed for economic reasons may have thermal constraints that are resolvable by SCED but result in high congestion costs. If an EAP is proposed primarily for economic reasons, the avoidable congestion must have resulted in:

(a) Over $2 million of congestion cost in a given month within the past 36 months; or

(b) $5 million of congestion cost over any three months within the past 36 month.

(3) ERCOT shall provide notification to the market of any approved, amended, or removed CMP or Remedial Action Scheme (RAS). ERCOT shall provide notification to the market of any RAP, AMP, or RAS that cannot be modeled in the Network Operations Model. ERCOT shall post to the Market Information System (MIS) Secure Area all CMPs and RASs and any unmodeled CMPs or RASs.

***[NOGRR258: Replace paragraph (3) above with the following upon system implementation of NPRR1198:*]**

(3) ERCOT shall provide notification to the market of any approved, amended, or removed CMP or Remedial Action Scheme (RAS). ERCOT shall provide notification to the market of any RAP, AMP, or RAS that cannot be modeled in the Network Operations Model. ERCOT shall post to the Market Information System (MIS) Secure Area all CMPs and RASs and any unmodeled CMPs or RASs.

(4) ERCOT shall provide notification to the market of any proposed RASs or PCAPs on the MIS Secure Area.

***[NOGRR258: Delete paragraph (4) above upon system implementation of NPRR1198 and renumber accordingly.*]**

(5) ERCOT is not required to provide notification to the market of any proposed TOAPs.

(6) All submittals related to CMPs or RASs must be emailed to ras_cmp@ercot.com.

11.2 Remedial Action Schemes

(1) Remedial Action Schemes (RASs) are designed to detect abnormal predetermined ERCOT System conditions and automatically take corrective actions to maintain a secure system. Any RAS proposed on or after June 24, 2020 may not be approved or implemented unless ERCOT has first determined that the RAS is necessary to avoid an actual or anticipated violation of transmission security criteria, as defined in Section 2.2.2, Security Criteria, that cannot be resolved through ERCOT market tools.

[NOGRR215: Replace paragraph (1) above with the following upon system implementation:]

(1) Remedial Action Schemes (RASs) are designed to detect abnormal predetermined ERCOT System conditions and automatically take corrective actions to maintain a secure system. Any RAS proposed on or after June 24, 2020 may not be approved or implemented unless ERCOT has first determined that the RAS is necessary to avoid an actual or anticipated violation of transmission security criteria, as defined in Section 2.2.2, Security Criteria, that cannot be resolved through ERCOT market tools, or unless the RAS would allow a Generation Resource of the type described in paragraph (3) of Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, to operate at a level that comports with the minimum deliverability criteria in Planning Guide Section 4.1.1.7.

(2) The following do not individually constitute a RAS:

(a) Protection systems installed for the purpose of detecting faults on Transmission Elements and isolating the faulted Transmission Elements;

(b) Schemes for automatic Under-Frequency Load Shedding (UFLS) and automatic Under-Voltage Load Shedding (UVLS) comprised of only distributed relays;

(c) Out-of-step tripping and power swing blocking;

(d) Automatic reclosing schemes;

(e) Schemes applied on a Transmission Element for non-fault condition, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage or overload to protect the Transmission Element against damage by removing it from service;

(f) Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and that are located at and monitor quantities solely at the same station as the Transmission Element being switched or regulated;

(g) FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device;

(h) Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched;

(i) Schemes that automatically de-energize a line for a non-faults operation when one end of the line is open;

(j) Schemes that provide anti-islanding protection (e.g., protect Load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage);

(k) Automatic sequences that proceed when manually initiated solely by a System Operator;

(l) Modulation of high voltage, direct current (HVDC) or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillation;

(m) Sub-synchronous resonance protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations); or

(n) Generation controls such as, but not limited to, Automatic Generation Control (AGC), generation excitation (e.g., Automatic Voltage Regulator (AVR) and Power System Stabilizers (PSSs)), fast valving, and speed governing.

(3) In addition to the requirements in the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards, RASs shall also meet the following requirements:

(a) A RAS may be proposed by a Transmission Service Provider (TSP) or Resource Entity, and be approved by ERCOT and the TSP(s) and/or Resource Entity(ies) included in the RAS prior to implementation;

(b) The design, implementation, and testing of the RAS shall be coordinated within the RAS Entity;

(c) The RAS shall be automatically armed when appropriate;

(d) The RAS shall not operate unnecessarily;

(e) A RAS designated as a Limited Impact RAS shall be reviewed according to the process described in paragraph (4)(e) below and subject to ERCOT approval;

(f) For a RAS not designated by ERCOT as a Limited Impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following as determined by the review process in paragraph (4)(e) below and subject to ERCOT approval:

(i) The ERCOT System shall remain stable;

(ii) Cascading shall not occur;

(iii) Applicable Facility Ratings shall not be exceeded;

(iv) ERCOT System voltages shall be within post-contingency voltage limits and post-contingency voltage deviation limits;

(v) Transient voltage responses shall be within acceptable limits.

(g) To avoid unnecessary RAS operation, the RAS Entity may provide a Real-Time status indication to the owner of any Generation Resource or Energy Storage Resource (ESR) controlled by the RAS to show when the flow on one or more of the RAS monitored Facilities exceeds 90% of the flow necessary to arm the RAS. The cost necessary to provide such status indication shall be the responsibility of the RAS Entity;

(h) The status indication of any automatic or manual arming/activation or operation of the RAS shall be provided as Supervisory Control and Data Acquisition (SCADA) alarm inputs to the owner(s) of any Facility controlled by the RAS;

(i) When a RAS is removed from service, the RAS Entity or a Designated Agent shall immediately notify ERCOT;

(j) When a RAS is returned to service, the RAS Entity or its Designated Agent shall immediately notify ERCOT. ERCOT shall modify its reliability constraints to recognize the availability of the RAS;

(k) The RAS Entity shall telemeter the status indication of the following items by SCADA to ERCOT for incorporation into ERCOT systems:

(i) Any automatic or manual arming/activation or operation of the RAS;

(ii) The in-service/out-of-service status of the RAS; and

(iii) Any additional related telemetry that already exists pertinent to the monitoring of the RAS (e.g. status indication of communications links between associated RAS equipment and the owner’s control center, arming limits of associated RAS equipment); and

(l) The TSP may receive telemetry for a Resource Entity owned RAS through ERCOT or through the RAS Entity, at the option of the TSP. The RAS Entity, at its own cost, must provide telemetry for Resource Entity owned RASs to the TSP upon request.

(4) The RAS Entity shall submit to ERCOT documentation of an existing, modified, proposed, or retiring RAS for review and compilation into an ERCOT RAS database using the form in Section 8, Attachment K, Remedial Action Scheme (RAS) Template. The documentation shall detail the design, operation, modeling, functional testing, and coordination of the RAS with other RASs, Automatic Mitigation Plans (AMPs), protection and control systems. The exit strategy described in the RAS submission shall identify the ERCOT endorsed transmission project or near-term mitigation that will address the constraint.

(a) ERCOT shall conduct a review of each proposed new or modified RAS and each proposed retirement of a RAS. Within five Business Days of receipt, ERCOT shall post the proposal to the Market Information System (MIS) Secure Area and shall issue a Market Notice describing the proposal and inviting submission of

Market Participant comments. Within 30 Business Days of receiving the proposal, ERCOT shall complete an evaluation of the proposal in accordance with paragraph (4)(e) below and shall issue a Market Notice approving or rejecting the proposal. ERCOT shall coordinate any additional time needed for the evaluation with the RAS Entity. Additionally, ERCOT shall conduct a review of each existing RAS at least once every three years or as required by changes in system conditions.

(b) The review of a proposed RAS shall be completed before the RAS is placed in service. The timing of placing the RAS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Network Operations Model Change Request (NOMCR) to ERCOT.

(c) Existing RASs that have already undergone at least one review shall remain in service during any subsequent review. Modifications to existing RASs may be implemented upon approval by ERCOT.

(d) The schedule for placing a RAS into service must be coordinated among ERCOT and the RAS Entity, and shall provide sufficient time to perform any necessary functional testing prior to its being placed in service.

(e) For any proposed, modified, or existing RAS, ERCOT's review of the RAS shall:

(i) Validate that RAS is needed to mitigate the system condition(s) or contingency(ies) for which it was designed, and that the RAS actions, designed timing, and arming conditions mitigate those system condition(s) or contingency(ies);

(ii) Identify any conflicts with the Protocols, NERC Reliability Standards, and this Operating Guide;

(iii) Validate that transient voltage responses are within acceptable limits as established by ERCOT;

(iv) Evaluate and document the consequences of misoperation, incorrect operation, unintended operation, or failure of a RAS. Additionally, validate that the RAS is designed to meet the requirements in paragraphs (3)(e) and (3)(f) above;

(v) Validate that the proposed RAS facilitates periodic testing and maintenance;

(vi) Determine whether or not the RAS is a Limited Impact RAS;

(vii) Validate that the proposed RAS avoids adverse interactions with other RASs, AMPs, protection and control systems, and applicable emergency procedures;

(viii) Evaluate the effects of future bulk electric system modifications on the design and operation of the RAS where applicable;

(ix) Validate the implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs);

(x) Validate the mechanism of procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designated to operate; and

(xi) Evaluate future transmission project(s) that will eliminate the need for the RAS.

(f) Upon completion of ERCOT's RAS review, ERCOT shall provide all results and underlying studies to the RAS Entity and each impacted TSP.

(g) If deficiencies are identified for a new, functionally modified, or retiring RAS by ERCOT or other parties' comments, the RAS Entity shall either submit an amended RAS proposal or withdraw the RAS proposal. The amended RAS proposal shall undergo the review process specified in paragraph (4)(e) above using the 30 Business Day RAS review timeline in paragraph (4)(a) above until the identified deficiencies have been resolved to the satisfaction of ERCOT.

(h) For any proposed retirement of a RAS, ERCOT shall evaluate whether the proposed retirement will cause any reliability concern, including whether the proposed retirement will adversely impact the dispatch of a Generation Resource or ESR subject to the minimum deliverability criteria set forth in Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria. After considering any comments submitted, if ERCOT does not identify any reliability concern, ERCOT shall issue a Market Notice indicating its approval of the proposed retirement of the RAS. If ERCOT does identify a reliability concern or an adverse impact to the dispatch of a Generation Resource or ESR subject to the minimum deliverability criteria set forth in Planning Guide Section 4.1.1.7, ERCOT shall issue a Market Notice denying the retirement.

(i) As part of the ERCOT review, ERCOT may notify the Steady State Working Group (SSWG), the Dynamics Working Group (DWG), and the System Protection Working Group (SPWG) of the RAS proposal, and each working group or any member of each working group may provide any comments, questions, or issues to ERCOT. ERCOT may work with the owner(s) of Facilities affected by the RAS as necessary to address all issues.

(j) ERCOT shall develop a method to include the RAS where practicable in Security-Constrained Economic Dispatch (SCED), Outage coordination, and Reliability Unit Commitment (RUC).

(k) ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the RAS.

(l) ERCOT shall update the RAS database at least once every 12 calendar months.

(5) ERCOT shall provide the results of the RAS evaluation including any identified deficiencies to the RAS Entity and impacted TSPs. If ERCOT's RAS evaluation identifies a deficiency within six calendar months, the RAS Entity shall develop and submit a corrective action plan, subject to ERCOT approval, to correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at ras_cmp@ercot.com if plan actions or timetables change and when the plan is completed.

(6) If ERCOT determines that a RAS is no longer needed, either as part of an ERCOT-initiated review or as a consequence of ERCOT's determination that a transmission project has addressed the condition(s) or contingency(ies) the RAS was designed to address, ERCOT shall issue a Market Notice proposing to retire the RAS and inviting comments from Market Participants on the proposed retirement. After considering all comments, if ERCOT confirms that the RAS is not needed, then ERCOT shall retire the RAS on a date specified in a separate Market Notice.

(7) The RAS Entity shall perform a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-protection system components at least once every six calendar years for a RAS not designated as a Limited Impact RAS, and once every 12 calendar years for a RAS designated as a Limited Impact RAS. For any identified deficiencies, the RAS Entity shall develop and submit a corrective action plan within six calendar months, and subject to ERCOT approval, to correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at ras_cmp@ercot.com if plan actions or timetables change and when the plan is completed.

11.2.1 Reporting of RAS Operations

(1) RAS Entity shall notify ERCOT of all RAS operations. Documentation of RAS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report form as an email to ras_cmp@ercot.com. Within 120 calendar days, the RAS Entity shall conduct an analysis of all RAS operations, misoperations, and failures. If deficiencies are identified, the RAS Entity shall develop and submit a corrective action plan within six calendar months, and subject to ERCOT approval, correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at ras_cmp@ercot.com if plan actions or timetables change and when the plan is completed. Analysis of RAS operational performance shall include, but is not limited to:

(a) Determination of whether system events or conditions appropriately armed or triggered the RAS;

(b) Determination of whether the RAS responded as designed;

(c) Determination of whether the RAS was effective in mitigating the performance issues it was designed to address; and

(d) Determination of whether the RAS operation resulted in any unintended or adverse system response.

(2) ERCOT shall report all RAS operations and misoperations to the Reliability Monitor for review. RAS arming or activation that ramps generation back is not considered an operation or misoperation with respect to reporting requirements to the Reliability Monitor and the NERC Regional Entity. A misoperation of a RAS with respect to reporting requirements to the Reliability Monitor and the NERC Regional Entity occurs when one of the items specified in paragraph (4) of Section 6.2.3, Performance Analysis Requirements for ERCOT System Facilities, occur. RAS Entities will provide a monthly report to ERCOT by the 15th of each month describing each instance a RAS armed/activated and reset during the previous month. The report will include the date and time of arming/activation and reset. ERCOT shall consolidate the monthly reports and forward to the Reliability Monitor and NERC Regional Entity on a quarterly basis.

(3) If a RAS which removes generation from service operates more than two times within a six month period and the operations are not a direct result of an ERCOT System disturbance or a contingency operation, ERCOT may require the Resource Entity(ies) representing the Generation Resource or ESR to decrease the available capability on the affected Resource(s). The amount of available capacity to be decreased shall be determined by ERCOT. The decreased available capacity on the Resource(s) shall remain until the Resource Entity(ies) provides documentation that demonstrates the Resource(s) can properly control output in a pre-contingency or normal ERCOT System condition.

11.3 Automatic Mitigation Plans

(1) Automatic Mitigation Plans (AMPs) are defined in Protocol Section 2.1, Definitions, and may be relied upon to detect predetermined abnormal system conditions and automatically take pre-coordinated corrective actions to maintain a secure system.

(2) AMPs must:

(a) Be proposed by a Transmission Service Provider (TSP) or Resource Entity, and be approved by ERCOT and the TSP(s) and/or Resource Entity(ies) included in the AMP prior to implementation;

(b) Be designed and implemented in coordination with the owners and operators of Facilities included in the AMP and approved by ERCOT;

(c) Be automatically armed when appropriate;

(d) Not operate unnecessarily;

(e) Comply with all applicable requirements in the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards; and

(f) Not include generation re-Dispatch or Load shed.

(3) AMP Owner(s) or a Designated Agent shall:

(a) Immediately notify ERCOT, when an AMP is removed from service and when an AMP is returned to service. ERCOT shall modify its reliability constraints to recognize the availability of the AMP;

(b) Telemeter the status indication of the following items by Supervisory Control and Data Acquisition (SCADA) to ERCOT for incorporation into ERCOT systems:

(i) Any automatic or manual arming/activation or operation of the AMP;

(ii) In-service/out-of-service status of the AMP; and

(iii) Any additional related telemetry that already exists pertinent to the monitoring of the AMP (e.g. status indication of communications links between associated AMP equipment and the owner's control center, arming limits of associated AMP equipment).

(c) Provide the status indication of any automatic or manual arming/activation or operation of the AMP as SCADA alarm inputs to the owner(s) of any Facility controlled by the AMP; and

(d) Submit documentation when proposing or modifying and/or deactivating/terminating an AMP that detail its design, operation and coordination of the AMP with other Remedial Action Schemes (RASs), AMPs, protection and control systems.

(5) ERCOT shall conduct a review of each proposed AMP, each proposed modification and proposed indefinite deactivation and/or termination of an existing AMP. Additionally, ERCOT shall conduct a review of each existing AMP annually or as required by changes in system conditions to ensure its continued effectiveness.

11.4 Remedial Action Plan

(1) Remedial Action Plans (RAPs) are defined in Protocol Section 2.1, Definitions, and may be relied upon in allowing additional use of the transmission system in Security-Constrained Economic Dispatch (SCED). Normally, it is desirable that a Transmission Service Provider (TSP) constructs Transmission Facilities adequate to eliminate the need for any RAP; however, in some circumstances, such construction may be unachievable in the available time frame.

(2) RAPs must:

(a) Be coordinated by ERCOT with all Transmission Operators (TOs) and Resource Entities included in the RAP, and approved by ERCOT;

(b) Be limited to the time required to construct replacement Transmission Facilities; however, the RAP will remain in effect if ERCOT has determined the replacement Transmission Facilities to be impractical;

(c) Comply with all applicable requirements in the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards;

(d) Clearly define and document TOs and Resource Entities included in the RAP actions;

(e) Must be able to resolve the issue for which it was designed over the range of conditions that might reasonably be experienced;

(f) Be executed by the TOs and/or Resource Entities;

(g) Have a 15-minute Rating greater than the Normal and Emergency Ratings for the Transmission Facilities it intends to resolve;

(h) Be defined in the Network Operations Model and considered in the SCED and Reliability Unit Commitment (RUC) processes. RAPs that cannot be modeled using ERCOT's existing infrastructure shall be rejected unless the Technical Advisory Committee (TAC) approves a plan to work around the infrastructure problem; and

(i) Not include generation re-Dispatch or Load shed.

(3) An approved RAP may be executed immediately after a contingency by the TOs and Resource Entities included in the RAP without instruction by ERCOT or shall be executed upon direction by ERCOT.

(4) ERCOT shall conduct a review of each existing RAP annually or as required by changes in system conditions to ensure its continued effectiveness. Each review shall proceed according to a process and timetable documented in ERCOT Procedures.

(5) ERCOT may approve the expiration of a RAP after consultation with the TOs and Resource Entities included in the RAP. ERCOT shall modify its reliability constraints to recognize the unavailability of the RAP.

11.4.1 Remedial Action Plan Process

(1) RAPs may be proposed by any Market Participant or may be developed by ERCOT. For RAPs submitted by Market Participants not registered as a TSP:

(a) ERCOT shall post RAPs submitted by a Market Participant not registered as a TSP on the Market Information System (MIS) Secure Area as soon as practicable, but no later than five Business Days of receipt.

(b) ERCOT shall provide a five Business Day comment period from the date when the proposed RAP under review is posted by ERCOT unless notice of a shorter comment period is provided.

(c) ERCOT shall consider all comments received within the five Business Day comment period on the proposed RAP, along with its own evaluation and those of the Transmission Facility owners, and either approve, modify or reject that proposed RAP.

(d) If a proposed RAP is modified or rejected, ERCOT shall post an explanation for the rejection or a description of the modification.

[NOGRR258: Replace item (d) above with the following upon system implementation of NPRR1198:]

(d) When a proposed RAP is approved, modified, or rejected, ERCOT shall post an explanation for the approval or rejection, or a description of the modification. If the RAP is approved the posting shall include the start date of the RAP.

11.5 Mitigation Plan

(1) Mitigation Plans are defined in Protocol Section 2.1, Definitions, and shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED). Normally, it is desirable that a Transmission Service Provider (TSP) constructs Transmission Facilities adequate to eliminate the need for a Mitigation Plan; however, in some circumstances, such construction may be unachievable in the available time frame.

(2) A Mitigation Plan may be proposed by any TSP, and be approved by ERCOT and the included Transmission Operator (TO) prior to implementation. Mitigation Plans must:

(a) Be coordinated with the TOs included in the Mitigation Plan;

(b) Limited in use to the time required to construct replacement Transmission Facilities; however, the Mitigation Plan will remain in effect if ERCOT has determined the replacement Transmission Facilities to be impractical;

(c) Comply with all requirements of the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards;

(d) Clearly define and document TO actions;

(e) Be executed by TOs;

(f) Be able to be implemented in a timeframe that will not result in loss of the overloaded Transmission Facility;

(g) Identify the most limiting protective relay setting beyond the 15-Minute Rating when developing the Mitigation Plan in advance or as soon as practicable when developing the Mitigation Plan in Real-Time;

(h) Not subject ERCOT to unacceptable risk of widespread cascading Outages; and

(i) Not include generation re-Dispatch.

(3) An approved Mitigation Plan may be executed immediately, post-contingency, by the TO without instruction by ERCOT or shall be executed upon direction by ERCOT.

(4) Restoration of any Load shed by executing the Mitigation Plan shall be coordinated with ERCOT.

11.6 Pre-Contingency Action Plans

(1) Pre-Contingency Action Plans (PCAPs) are defined in Protocol Section 2.1, Definitions, and are implemented in anticipation of a contingency. Normally, it is desirable that a Transmission Service Provider (TSP) construct Transmission Facilities adequate to eliminate the need for any PCAP; however, in some circumstances, such construction may be unachievable in the available time frame.

(2) A PCAP may be proposed by any Market Participant, and be approved by ERCOT and the Transmission Operator (TO) included in the PCAP prior to implementation. PCAPs must:

(a) Be coordinated with the TOs included in the PCAP;

(b) Be limited in use to the time required to construct replacement Transmission Facilities and until such Facilities are placed in-service, or the PCAP is no longer needed; however, the PCAP will remain in effect if ERCOT has determined the replacement Transmission Facilities to be impractical;

(c) Comply with all requirements of the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards;

(d) Clearly define and document TO actions;

(e) Be executed by TOs; and

(f) Not include generation re-Dispatch or Load shed.

(3) An approved PCAP may be executed immediately prior to a contingency by the TO without instruction by ERCOT, or shall be executed upon direction by ERCOT.

(4) All proposed, approved, amended, and removed PCAPs shall be managed in accordance with paragraph (4) of Section 11.1, Introduction.

(5) ERCOT may limit the quantity of PCAPs that are used.

11.6.1 Pre-Contingency Action Plan Process

(1) PCAPs may be proposed by any Market Participant or may be developed by ERCOT. For PCAPs submitted by Market Participants not registered as a TSP:

(a) ERCOT shall post PCAPs submitted by a Market Participant not registered as a TSP on the Market Information System (MIS) Secure Area as soon as practicable, but no later than five Business Days of receipt.

(b) ERCOT shall provide a five Business Day comment period from the date when the proposed PCAP under review is posted by ERCOT unless notice of a shorter comment period is provided.

(c) ERCOT shall consider all comments received within the five Business Day comment period on the proposed PCAP, along with its own evaluation and those of the Transmission Facility owners, and either approve, modify or reject that proposed PCAP.

(d) If a proposed PCAP is modified or rejected, ERCOT shall post an explanation for the rejection or a description of the modification

11.7 Temporary Outage Action Plan

(1) Temporary Outage Action Plans (TOAPs) are defined in Protocol Section 2.1, Definitions, and shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED).

(2) A TOAP may be proposed by any Market Participant and be approved by ERCOT and the Transmission Operator (TO) included in the TOAP prior to implementation. TOAPs must:

(a) Be coordinated with the TOs included in the TOAP;

(b) Limit use to the duration of a specific Transmission Facility or Resource Outage;

(c) Comply with all requirements of the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards;

(d) Clearly define and document TO actions;

(e) Be executed by TOs;

(f) Be implemented in a timeframe that will not result in loss of the overloaded Transmission Facility;

(g) Identify the most limiting protective relay setting beyond the 15-Minute Rating when developing the TOAP in advance or as soon as practicable when developing the TOAP in Real-Time; and

(h) Not subject ERCOT to unacceptable risk of widespread cascading Outages; and

(i) Not include generation re-Dispatch.

(3) An approved TOAP may be executed immediately, post-contingency, by the TO without instruction by ERCOT or shall be executed upon direction by ERCOT.

(4) ERCOT may limit the quantity of TOAPs that are used.

(5) Restoration of any Load shed by executing the TOAP shall be coordinated with ERCOT.

[NOGRR258: Insert Section 11.8 below upon system implementation for NPRR1198:]

11.8 Extended Action Plans (EAPs)

(1) Extended Action Plans (EAPs) must be approved prior to implementation by ERCOT, the Transmission Operators (TOs) that operate the affected equipment, and Resource Entities that are directly impacted operationally. Impacts resulting from price and Dispatch changes due to market clearing processes shall not constitute a direct operational impact under this section. EAPs must:

(a) Be accepted by the Resource Entities and TOs that are directly impacted operationally by the EAP;

(b) Be restored to normal configuration when either:

(i) A transmission project intended to address the congestion is placed in-service, if such a project has been made public and it was identified by either the TO during the initial EAP review, or by a Transmission Service Provider (TSP) during the EAP comment period; or

(ii) A period of temporary congestion is expected to end, if such temporary congestion and its estimated end date were identified during the initial EAP review. For chronic congestion which does not have an identified transmission project solution or expected end, an end date for the EAP must be proposed as if it is temporary congestion.

(c) Comply with all requirements of the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards;

(d) Clearly define and document TO actions;

(e) Be executed by TOs; and

(f) Not include generation re-Dispatch or Load shed.

(2) Prior to approving an EAP proposal for economic reasons on the ERCOT Transmission Grid, ERCOT must verify that the EAP:

(a) Meets all of the criteria in paragraph (1) above;

(b) Does not result in radial Load;

(c) Does not negatively impact current or scheduled Transmission Facility Outages;

(d) Does not create new binding thermal constraints or voltage violations, or increase flow on any existing binding constraint by more than 2% for 69 kV and 1% for 115 kV and above;

(e) Does not negatively impact any Generic Transmission Constraints (GTCs), decrease Generic Transmission Limits (GTLs), or create new instability situations;

(f) Provides more than $1 million savings to total production cost or total congestion cost with the EAP action in place compared to generation re-Dispatch alone. This can be established either by using annual production cost model simulation or other methods acceptable to ERCOT;

(g) Limits the action to changing the normal status of circuit breakers at up to three substations;

(h) If applicable, is limited to a post-contingency generation trip of no more than ERCOT frequency bias;

(i) Does not impact the ability of a Resource to meet its minimum deliverability criteria described in Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria; and

(j) Has not been previously rejected by ERCOT for disqualification under criteria in paragraphs (b) through (i) above, unless there have been major changes to the system configuration or EAP proposal.

(3) An approved EAP may be executed by the TO in coordination with ERCOT, on the effective date of the EAP.

(4) All proposed, approved, amended, and removed EAPs shall be managed in accordance with paragraph (4) of Section 11.1, Introduction.

(5) ERCOT may limit the quantity of EAPs that are used.

(6) ERCOT may reject proposals that fail to practicably assess impact to operations and reliability.

(7) The implementation of an approved EAP may be temporarily suspended by the TO or by ERCOT for reliability reasons, or for the duration of a Transmission Facility Outage if the EAP interferes with a TO's ability to take the outage. The existence of an EAP shall not, in and of itself, prevent a requested Transmission Facility Outage from being approved by ERCOT.

(8) ERCOT shall conduct a review of each existing EAP annually or as required by changes in system conditions to ensure its continued effectiveness. Each review shall proceed according to a process and timetable documented in ERCOT procedures.

[NOGRR258: Insert Section 11.8.1 below upon system implementation of NPRR1198:]

11.8.1 Extended Action Plan (EAP) Process

(1) EAPs proposed by a Transmission and/or Distribution Service Provider (TDSP) primarily for reliability reasons have an expedited review and are not subject to the process outlined in this section. EAPs proposed primarily for economic reasons need to follow the process outlined below in addition to the requirements in Section 11.8, Extended Action Plans (EAPs):

(a) The EAP must be submitted to ERCOT for initial review. ERCOT must provide the submission of qualified EAPs to impacted TOs and Resource Entities directly impacted operationally. Impacts resulting from price and Dispatch changes due to market clearing processes shall not constitute a direct operational impact under this paragraph.

(i) Impacted TOs, and Resource Entities directly impacted operationally, will provide either a concurrence with or an objection to the proposed EAP to ERCOT in writing within 30 days of receipt, and may request additional time if necessary while making reasonable efforts to consider proposed EAPs as soon as possible;

(ii) Impacted TOs may limit the quantity of EAPs they have under evaluation, on the basis of undue or excessive work load, and will include this as the reason for objection to an EAP, if applicable; and

(iii) An objection by either an impacted TO or a Resource Entity directly impacted operationally, will result in an initial rejection of the proposed EAP by ERCOT.

(b) EAPs submitted by a Market Participant will be posted on the Market Information

System (MIS) Secure Area by ERCOT within five Business Days of receipt of a complete submission.

(c) ERCOT will provide a 30 day comment period from the date the proposed EAP is posted to the MIS Secure Area by ERCOT, unless notice of a shorter comment period is provided by ERCOT.

(d) ERCOT shall consider all comments received within the 30 day comment period on the proposed EAP, along with its own evaluation and those of the Transmission Facility owners, and either approve, modify, or reject the proposed EAP within 15 days, unless extended by ERCOT.

(e) When a proposed EAP is approved, modified or rejected, ERCOT shall post an explanation for the approval or rejection, or a description of the modification within five Business Days of its determination. If the EAP is approved, the posting shall include the start date and end date or associated Transmission Facility change that will determine the end date of the EAP.

(2) The implementation and management of EAPs will be facilitated through the Network Operations Model Change Request (NOMCR) and Outage scheduling processes as follows:

(a) A NOMCR will be submitted by the applicable TO or Resource Entity to implement an approved EAP in the Network Operations Model. This NOMCR will be submitted prior to the EAP's start date and during the appropriate NOMCR production model load schedule. The EAP start date should align with the NOMCR production model load date, and if these two dates differ, Transmission Facility Outages will be submitted by the applicable TO or Resource Entity to manage interim configuration changes until the submitted NOMCR implements the EAP in the Network Operations Model.

(b) If a TO or ERCOT identifies that an approved EAP will create a conflict with a current or scheduled Transmission Facility Outage or other system conditions, the applicable TO or Resource Entity will reverse the EAP configuration by submitting the necessary Transmission Facility Outage(s) and/or by utilizing the NOMCR process to address the timeframe for which the conflict is expected to exist. ERCOT shall also post any such EAP changes to the MIS Secure Area.

(c) A NOMCR will be submitted by the applicable TO or Resource Entity to reverse an EAP prior to the scheduled EAP end date and during the appropriate NOMCR production model load schedule. Transmission Facility Outages may also be used to manage interim configuration changes before the NOMCR takes effect, if necessary.

(3) A Market Participant or ERCOT may propose that an existing EAP be suspended, modified, or extended. ERCOT will process any proposed EAP modifications or extensions as described by paragraphs (1)(a) through (e) above.