ERCOT Nodal Operating Guides

June 1, 2010

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

ERCOT Nodal Operating Guide
Table of Contents

August 1, 2010

ERCOT Nodal Operating Guides

Section 1: Overview

August 1, 2010

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

*** All References to Protocols and Operating Guides throughout this document are to Nodal Protocols and Nodal Operating Guides*

1 OVERVIEW

1.1 Document Purpose

(1) These Electric Reliability Council of Texas (ERCOT) Operating Guides supplement the ERCOT Protocols. The ERCOT Operating Guides provide more detail and establish additional operating requirements for those organizations and entities operating in, or potentially impacting the reliability of the Transmission Grid in the ERCOT Region, as shown below in Figure 1, ERCOT Regional Map.

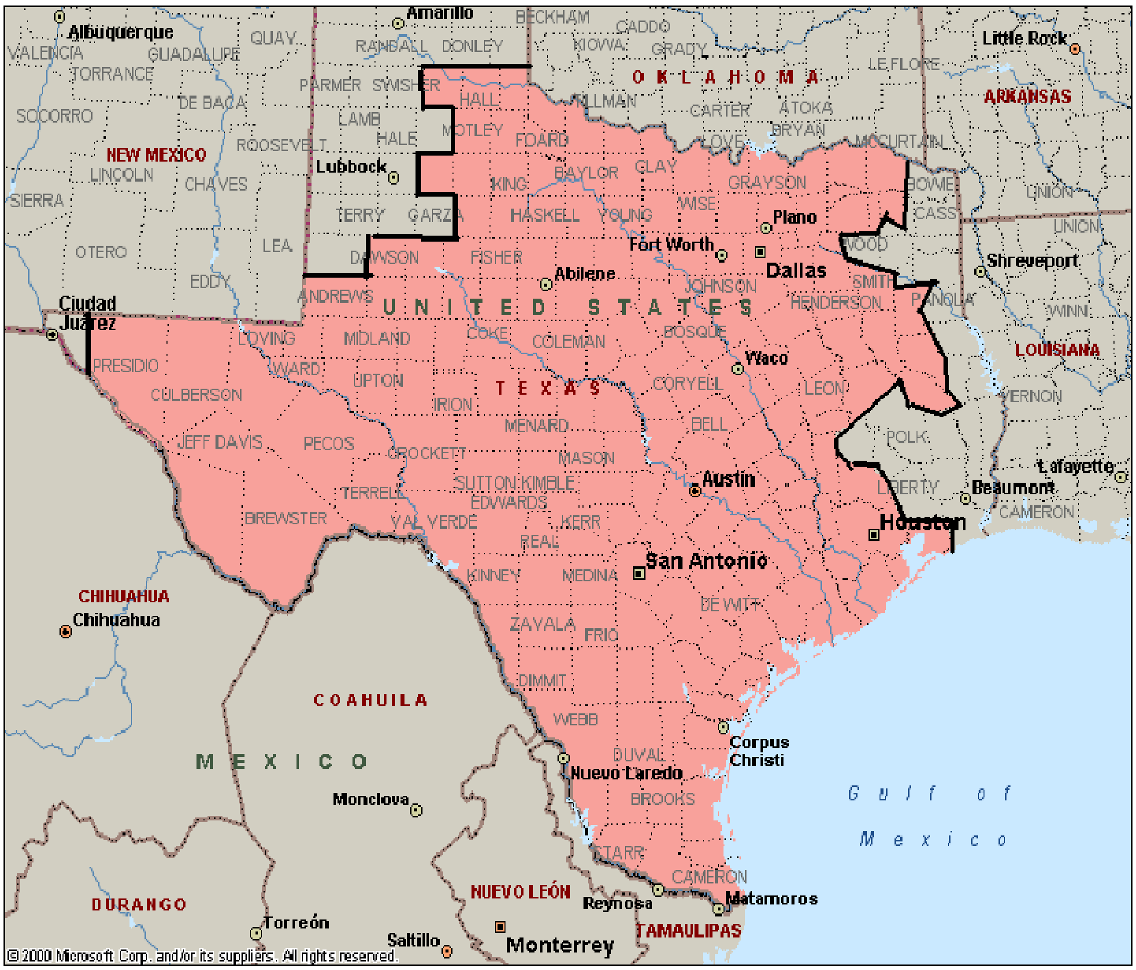


Figure 1 – ERCOT Regional Map

(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 NERC Reliability Standards and the ERCOT Protocols.

1.2 Document Relationship

(1) These Operating Guides are written to be consistent with the ERCOT Protocols and to implement the NERC Reliability Standards. ERCOT Protocols supersede these Operating Guides. The Public Utilities 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, Texas Regional Entity (TRE) Staff, 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 Operations Working Group (OWG), the Reliability and Operations Subcommittee (ROS), the Technical Advisory Committee (TAC), or ERCOT Board 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 ERCOT Board or committee procedures.

(3) 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, Process for Nodal Protocol Revision.

(4) 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, and references to ERCOT Protocols, PUCT Substantive Rules, the Public Utility Regulatory Act (PURA), North American Electric Reliability Corporation (NERC) regulations, Federal Energy Regulatory

Commission (FERC) rules, etc. Updates to the ERCOT Load Shed Table in Section 4.5.3.4, Load Shed Obligation, shall be processed as an Administrative NOGRR.

(b) ERCOT shall post such Administrative NOGRRs to the ERCOT website and distribute the NOGRR to the OWG at least ten Business Days before implementation. If no Entity submits comments to the Administrative NOGRR in accordance with paragraph (1) of Section 1.3.4.3, Operations Working Group Review and Action, ERCOT shall implement it according to paragraph (4) of Section 1.3.6, Nodal Operating Guide Revision Implementation. If any ERCOT Member, Market Participant, PUCT Staff, TRE Staff or ERCOT submits comments to the Administrative NOGRR, then it shall be processed in accordance with the NOGRR process outlined in Section 1.3.

1.3.2 Submission of a Nodal Operating Guide Revision Request

The following Entities may submit a NOGRR:

(a) Any Market Participant;

(b) Any ERCOT Member;

(c) PUCT Staff;

(d) TRE Staff;

(e) ERCOT; and

(f) 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 Operations Working Group

(1) The OWG shall review and recommend action on formally submitted NOGRRs, provided that:

(a) OWG meetings are open to ERCOT, ERCOT Members, Market Participants, TRE Staff, and PUCT Staff; and

(b) Each Market Segment is allowed to participate.

(2) Where additional expertise is needed, the OWG may request that ROS refer a NOGRR to existing TAC subcommittees, working groups or task forces for review and comment on the NOGRR. Suggested modifications or alternative modifications if a consensus recommendation is not achieved by a non-voting working group or task force, to the NOGRR should be submitted by the chair or the chair's designee on behalf of the commenting subcommittee, working group or task force as comments on the NOGRR for consideration by OWG. However, the OWG shall retain ultimate responsibility for the processing of all NOGRRs.

(3) The OWG shall ensure that the Operating Guides are compliant with the ERCOT Protocols. As such, the OWG 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 OWG 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) ERCOT shall consult with the OWG chair to coordinate and establish the meeting schedule for the OWG. The OWG shall meet at least once per month, unless no NOGRRs were submitted during the prior 24 days, and shall ensure that reasonable advance notice of each meeting, including the meeting agenda, is posted on the ERCOT website.

1.3.4 Nodal Operating Guide Revision Procedure

1.3.4.1 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. 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) Impact Analysis (applicable only for a NOGRR submitted by ERCOT);

(d) List of affected Operating Guide sections and subsections;

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

(f) 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 once a NOGRR is completed, ERCOT shall post the NOGRR on the ERCOT website and distribute to the OWG within three Business Days.

1.3.4.2 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 the OWG recommends approval of the NOGRR. If the OWG has recommended approval of the NOGRR, the Request for Withdrawal must be approved by ROS if the NOGRR has not yet been recommended for approval by ROS.

(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 approved or recommended for approval by TAC.

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

(5) Once a NOGRR that requires an ERCOT project for implementation is approved by the ERCOT Board or a NOGRR that does not require an ERCOT project for implementation is approved by TAC, such NOGRR cannot be withdrawn.

1.3.4.3 Operations Working Group Review and Action

(1) Any ERCOT Member, Market Participant, PUCT Staff, TRE Staff 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 21 days from the posting date of the NOGRR. Comments submitted after the 21 day comment period may be considered at the discretion of OWG after these comments have been posted. Comments submitted in accordance with the instructions on the ERCOT website, regardless of date of submission, shall be posted to the ERCOT website and distributed electronically to the OWG within three Business Days of submittal.

(3) The OWG shall consider the NOGRR at its next regularly scheduled meeting after the end of the 21 day comment period, unless the 21 day comment period ends less than three

Business Days prior to the next regularly scheduled OWG meeting. In that case, the NOGRR will be considered at the next subsequent regularly scheduled OWG meeting. At such meeting, the OWG may take action on the NOGRR. In considering action on a NOGRR, the OWG may:

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

(b) Recommend rejection of the NOGRR;

(c) If no consensus can be reached on the NOGRR, present options for ROS consideration;

(d) Defer decision on the NOGRR; or

(e) Recommend that ROS refer the NOGRR to a subcommittee, working group or task force as provided in Section 1.3.3, Operations Working Group.

(4) Within three Business Days after OWG takes action, ERCOT shall issue an OWG Report reflecting the OWG action and post it to the ERCOT website. The OWG Report shall contain the following items:

(a) Identification of submitter;

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

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

(d) Proposed effective date of the NOGRR;

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

(f) OWG action.

1.3.4.4 Comments to the Operations Working Group Report

(1) Any ERCOT Member, Market Participant, PUCT Staff, TRE Staff, or ERCOT may comment on the OWG Report. Within three Business Days of receipt of comments related to the OWG Report, ERCOT shall post such comments to the ERCOT website. Comments submitted in accordance with the instructions on the ERCOT website, regardless of date of submission, shall be posted on the ERCOT website within three Business Days of submittal.

(2) The comments on the OWG Report will be considered at the next regularly scheduled OWG or ROS meeting where the NOGRR is being considered.

1.3.4.5 Nodal Operating Guide Revision Request Impact Analysis

(1) ERCOT shall submit to OWG an initial Impact Analysis based on the original language in the NOGRR with any ERCOT-sponsored NOGRR. The initial Impact Analysis will provide OWG with guidance as to what ERCOT computer systems, operations, or business functions could be affected by the NOGRR as submitted.

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

(3) The Impact Analysis shall assess the impact of the proposed NOGRR on ERCOT 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.

(4) Unless a longer review period is warranted due to the complexity of the proposed OWG Report, ERCOT shall issue an Impact Analysis for a NOGRR for which OWG has recommended approval of prior to the next regularly scheduled OWG meeting. ERCOT shall post the results of the completed Impact Analysis on the ERCOT website. 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 to the OWG.

1.3.4.6 Operations Working Group Review of Impact Analysis

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

(2) After consideration of the Impact Analysis and the OWG Report, ERCOT shall issue a revised OWG Report and post it on the ERCOT website within three Business Days of the OWG consideration of the Impact Analysis and the OWG Report. If OWG revises the proposed NOGRR, ERCOT shall update the Impact Analysis, if necessary, and issue the updated Impact Analysis to ROS. 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 to ROS.

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

1.3.4.7 Reliability and Operations Subcommittee Vote

(1) ROS shall consider any NOGRRs that OWG has submitted to ROS for consideration for which both an OWG Report and an Impact Analysis (as updated if modified by OWG under Section 1.3.4.6, Operations Working Group Review of Impact Analysis) have been posted on the ERCOT website. The following information must be included for each NOGRR considered by ROS:

(a) The OWG Report and Impact Analysis; and

(b) Any comments timely received in response to the OWG Report.

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

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

(b) Reject the NOGRR;

(c) Defer decision on the NOGRR;

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

(e) Refer the NOGRR to another ROS working group or task force or another TAC subcommittee 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 ROS unless at the same meeting ROS later votes to recommend approval of, defer, remand, or refer the NOGRR. If a motion to recommend approval of a NOGRR fails via email vote according to the Technical Advisory Committee Procedures, the NOGRR shall be deemed rejected by ROS unless at the next regularly scheduled ROS meeting or in a subsequent email vote prior to the meeting, ROS votes to recommend approval of, defer, remand, or refer the NOGRR. The rejected NOGRR shall be subject to appeal pursuant to Section 1.3.4.12, Appeal of Action.

(4) Within three Business Days after ROS takes action on the NOGRR, ERCOT shall issue a ROS Report reflecting the ROS action and post it on the ERCOT website. The ROS Report shall contain the following items:

(a) Identification of the submitter of the NOGRR;

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

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

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

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

(f) OWG action; and

(g) ROS action.

1.3.4.8 ERCOT Impact Analysis Based on Reliability and Operations Subcommittee Report

ERCOT shall review the ROS Report and, if necessary, update the Impact Analysis as soon as practicable. If the NOGRR does not require a project assigned to the Unfunded Project List, ERCOT shall issue 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 to TAC.

1.3.4.9 PRS Review of Project Prioritization

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.

1.3.4.10 Technical Advisory Committee Vote

(1) Upon issuance of a ROS Report and Impact Analysis to TAC, TAC shall review the ROS Report and the Impact Analysis at the following month's regularly scheduled meeting. For Urgent NOGRRs, TAC shall review the ROS Report and Impact Analysis at its next regularly scheduled meeting unless a special meeting is required due to urgency of the NOGRR.

(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) Approve the NOGRR as recommended in the ROS Report or as modified by TAC, if the NOGRR does not require an ERCOT project for implementation;

(b) Recommend approval of the NOGRR as recommended in the ROS Report or as modified by TAC, if the NOGRR requires an ERCOT project for implementation;

(c) Reject the NOGRR;

(d) Defer decision on the NOGRR;

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

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

(3) If a motion is made to approve or 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 approve, recommend approval of, defer, remand, or refer the NOGRR. If a motion to approve or 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 approve, recommend approval of, defer, remand, or refer the NOGRR. The rejected NOGRR shall be subject to appeal pursuant to Section 1.3.4.12, Appeal of Action

(4) If the NOGRR is approved or recommended for approval by TAC, as recommended by ROS or modified by TAC, TAC shall review and approve or modify the proposed effective date.

(5) Within three Business Days after TAC takes action on a NOGRR, ERCOT shall issue a TAC Report reflecting the TAC action and post it 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; and

(g) TAC action;

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

(7) TAC shall consider the project priority of each NOGRR requiring an ERCOT project for implementation and make recommendations to the ERCOT Board. If TAC recommends approval of a NOGRR that requires an ERCOT project which can be funded in the current ERCOT budget cycle based upon its priority and ranking, ERCOT shall forward the TAC Report to the ERCOT Board for consideration pursuant to Section 1.3.4.11, ERCOT Board Vote.

(8) If TAC recommends approval of a NOGRR that requires a project for implementation that cannot be funded within the current ERCOT budget cycle, ERCOT shall prepare a TAC Report and post the report on the ERCOT website within three Business Days of the TAC recommendation concerning the NOGRR. ERCOT shall assign the NOGRR recommended

for approval to the Unfunded Project List until the ERCOT Board approves an annual ERCOT budget in a manner that indicates funding would be available in the new budget cycle to implement the project if approved by the ERCOT Board; in such case, the TAC Report would be provided at the next ERCOT Board meeting following such budget approval for the ERCOT Board's consideration under Section 1.3.4.11.

(9) Notwithstanding the above, a NOGRR on the Unfunded Project List may be removed from the list and provided to the ERCOT Board for approval, as set forth in Protocol Section 21.9, Review of Project Prioritization, Review of Unfunded Project List, and Annual Budget Process. ERCOT shall maintain the Unfunded Project List to track projects that cannot be funded in the current ERCOT budget cycle. Any NOGRR approved by TAC but assigned to the Unfunded Project List may be challenged by appeal as otherwise set forth in Section 1.3.4.12.

1.3.4.11 ERCOT Board Vote

(1) For any NOGRR requiring an ERCOT project for implementation, 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 following month's 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) Approve the NOGRR as recommended in the TAC Report or as modified by the ERCOT Board;

(b) Reject the NOGRR;

(c) Defer decision on the NOGRR; or

(d) Remand the NOGRR to TAC with instructions.

(3) If a motion is made to approve 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 approve, defer, or remand the NOGRR. The rejected NOGRR shall be subject to appeal pursuant to Section 1.3.4.12, Appeal of Action.

(4) If the NOGRR is approved by the ERCOT Board, as recommended by TAC or as modified by the ERCOT Board, the ERCOT Board shall review and approve or modify the proposed effective date.

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

1.3.4.12 Appeal of Action

(1) Any ERCOT Member, Market Participant, PUCT Staff, TRE Staff or ERCOT may appeal an OWG action to recommend rejection of, defer, or recommend referral of a NOGRR directly to ROS. Such appeal to the ROS must be submitted electronically to ERCOT by completing the designated form provided on the ERCOT website within ten Business Days after the date of the relevant OWG 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. If the appeal is submitted to ERCOT at least 11 days before the next regularly scheduled ROS meeting, ERCOT shall place the appeal on the agenda of the next regularly scheduled ROS meeting. If the appeal is submitted to ERCOT less than 11 days before the next regularly scheduled ROS meeting, the ROS will hear the appeal at the next subsequent regularly scheduled ROS meeting. An appeal of a NOGRR to ROS suspends consideration of the NOGRR until the appeal has been decided by ROS.

(2) Any ERCOT Member, Market Participant, PUCT Staff, TRE Staff, or ERCOT may appeal a ROS action to reject, defer, remand 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 ten Business 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. If the appeal is submitted to ERCOT at least 11 days before the next regularly scheduled TAC meeting, ERCOT shall place the appeal on the agenda of the next regularly scheduled TAC meeting. If the appeal is submitted to ERCOT less than 11 days before the next regularly scheduled TAC meeting, TAC will hear the appeal at the next subsequent regularly scheduled TAC meeting. An appeal of a NOGRR to TAC suspends consideration of the NOGRR until the appeal has been decided by TAC.

(3) Any ERCOT Member, Market Participant, PUCT Staff, TRE Staff or ERCOT may appeal a TAC action to approve, reject, defer, 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.

(4) Any ERCOT Member, Market Participant, PUCT Staff or TRE Staff 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.

1.3.5 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 reasonably 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:

(a) Requires immediate attention due to:

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

(ii) The crucial nature of a Settlement activity conducted pursuant to any Settlement formula; and

(b) Is of a nature that allows for rapid implementation without negative consequence to the reliability and integrity of the ERCOT System or market operations.

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

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

(5) If the submitter desires to further expedite processing of the NOGRR, a request for voting via electronic mail may be submitted to the ROS chair. The ROS chair may grant the request for voting via electronic mail. Such voting shall be conducted pursuant to the Technical Advisory Committee Procedures. If ROS recommends approval of an Urgent NOGRR, ERCOT shall issue an ROS Report reflecting the ROS action and post it on the ERCOT website within three Business Days after ROS takes action. The ROS chair may request action from ROS to accelerate or alter the procedures described herein, as needed, to address the urgency of the situation.

(6) Any revisions to the Nodal Operating Guides that take effect pursuant to an Urgent request shall be subject to an Impact Analysis pursuant to Section 1.3.4.8, ERCOT Impact Analysis Based on Reliability and Operations Subcommittee Report, and TAC consideration pursuant to Section 1.3.4.10, Technical Advisory Committee Vote.

1.3.6 Nodal Operating Guide Revision Implementation

(1) For NOGRRs that do not require an ERCOT project for implementation, upon TAC approval, ERCOT shall implement NOGRRs on the first day of the month following TAC approval, unless otherwise provided in the TAC Report for the approved NOGRR.

(2) For NOGRRs that require an ERCOT project for implementation, upon ERCOT Board approval, ERCOT shall implement NOGRRs on the first day of the month following

ERCOT Board approval, unless otherwise provided in the Board Report for the approved NOGRR.

(3) For NOGRRs for which an effective date other than the first day of the month following TAC or ERCOT Board approval, as applicable, is provided, the ERCOT Impact Analysis shall provide an estimated implementation date and ERCOT shall provide 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 TAC or Board Report, as applicable, for the approved NOGRR.

(4) ERCOT shall implement an Administrative NOGRR on the first day of the month following the end of the ten Business Day posting requirement outlined in Section 1.3.1, Introduction.

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

[Back to Top]

Automatic Generation Control (AGC)
Application that receives signals from ERCOT for Regulation deployment and Responsive Reserve deployment and causes Generation Resources providing these Ancillary Services to respond in accordance with their participation factor and ramp rate to meet the received deployments.

B

[Back to Top]

C

[Back to Top]

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

Constant Frequency Control (CFC)
An operating mode of an AGC system. While in CFC, an AGC system will monitor only the frequency error to determine Resource adjustments needed to balance sources and obligations. CFC controls generation to increase or decrease by the amount of frequency deviation multiplied by the bias.

Credible Single Contingency

(A) Definition applicable to Operational Planning:

(1) A single facility, comprised of transmission line, auto transformer, or other associated pieces of equipment. This includes multiple equipment Outaged or interrupted during a single fault (single fault multiple element, SFME).

(2) The Forced Outage of a double-circuit transmission line (DCKT) in excess of 0.5 miles in length will always be considered a credible single contingency for all security constrained unit commitment decisions. The Forced Outage of a DCKT in excess of 0.5 miles in length will only be considered a credible single contingency for energy deployment decisions for any of the following operating conditions characterized by high DCKT Outage probability or consequence:

(a) High Outage Probability:

(i) Severe weather conditions are forecasted by ERCOT in the vicinity of the DCKT.

(ii) During any ERCOT declared Watch or for any operating conditions characterized by high DCKT Outage probability or consequence.

(iii) Weather conditions indicate a high risk of insulator flashover on the DCKT.

(iv) Individual circuits that are part of the DCKT have experienced repeated Forced Outages within the preceding 48 hours possibly indicating unresolved problems.

(v) A high risk of DCKT Outage exists due to fire in progress near the DCKT right-of-way.

(b) High Outage Consequence:

(i) Another Transmission Facility, which significantly increases the impact of an Outage to the DCKT, is out of service.

(ii) Studies affirmatively indicate Outage of the DCKT would result in cascading Outages or voltage collapse.

(iii) Studies affirmatively indicate Outage of the DCKT poses a significant risk of uncontrolled Outages because it would result in equipment overloads, which cannot be eliminated through execution of specific, predefined operating procedures such as Remedial Action Plans (RAPs), which may include the use of energy Dispatch Instructions in time to prevent equipment damage or failure.

(3) Any generating unit:

(a) A combined-cycle facility shall be considered a single generating unit; or.

(b) Each unit of a combined-cycle facility will be considered a single generating unit if the combustion turbine and the steam turbine can operate separately, as stated in the Resource Asset Registration form on the Market Information System (MIS) Public Area.

(4) With any single generating unit unavailable, and with any other generation preemptively redispatched, the contingency loss of a single Transmission Facility (either without a fault or subsequent to a normally-cleared non-three-phase fault) with all other facilities normal should not cause the following:

(a) Cascading or uncontrolled Outages;

(b) Instability of generating units at multiple plant locations; or

(c) Interruption of service to firm demand or generation other than that isolated by the transmission facility, following the execution of all automatic operating actions such as relaying and Special Protection Systems (SPSs).

Furthermore, the loss should result in no damage to or failure of equipment and, following the execution of specific non-automatic predefined operator-directed actions (i.e., RAPs) such as generation schedule changes or curtailment of interruptible Load, should not result in applicable voltage or thermal ratings being exceeded.

(B) Definition applicable to Transmission Planning:

(1) A single facility, comprised of transmission line, auto transformer, or other associated pieces of equipment. This includes multiple equipment outaged or interrupted during a single fault (single fault multiple element (SFME)).

(2) The Forced Outage of a double-circuit transmission line (DCKT) in excess of 0.5 miles in length (either without a fault or subsequent to a normally-cleared non-three-phase fault) with all other facilities normal should not cause the following:

(a) Cascading or uncontrolled outages;

(b) Instability of generating units at multiple plant locations; or

(c) Interruption of service to firm demand or generation other than that isolated by the transmission facility, following the execution of all automatic operating actions such as relaying and special protection systems.

Furthermore, the loss should result in no damage to or failure of equipment and, following the execution of specific non-automatic predefined operator-directed actions (i.e., RAPs) such as generation schedule changes or curtailment of interruptible Load, should not result in applicable voltage or thermal ratings being exceeded.

(3) Any generating unit:

(a) A combined-cycle facility shall be considered a single generating unit; or.

(b) Each unit of a combined-cycle facility will be considered a single generating unit if the combustion turbine and the steam turbine can operate separately, as stated in the Resource Asset Registration form on the MIS Public Area.

(4) With any single generating unit unavailable, and with any other generation preemptively redispatched, the contingency loss of a single Transmission Facility (either without a fault or subsequent to a normally-cleared non-three-phase fault) with all other facilities normal should not cause the following:

(a) Cascading or uncontrolled outages;

(b) Instability of generating units at multiple plant locations; or

(c) Interruption of service to firm demand or generation other than that isolated by the transmission facility, following the execution of all automatic operating actions such as relaying and special protection systems.

Furthermore, the loss should result in no damage to or failure of equipment and, following the execution of specific non-automatic predefined operator-directed actions (i.e., RAPs) such as generation schedule changes or curtailment of interruptible Load, should not result in applicable voltage or thermal ratings being exceeded.

(5) All normal and contingency conditions outlined in North American Electric Reliability Council (NERC) Planning Standards and any subsequent revisions.

D

[Back to Top]

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

E

[Back to Top]

F

[Back to Top]

G

[Back to Top]

Generator Reactive Power Sign/Direction Terminology

(1) Lagging power factor operating condition is when MVAr flow is out of the generating unit (overexcited generator) and is considered to be positive (+) flow, i.e., in the same direction as MW power flow. The generator is producing MVArs.

(2) Leading power factor operating condition is when VAr flow is into the generating unit (underexcited generator) and is considered to be negative (-) flow, i.e., in the opposite direction as MW power flow. The generator is absorbing MVArs.

H

[Back to Top]

I

[Back to Top]

Inadvertent Energy
The difference between the ERCOT System actual net interchange and the ERCOT System scheduled net interchange.

Interchange

Net Actual Interchange
The algebraic sum of the power flows of the ERCOT System interconnections with other non-ERCOT Systems. Sign convention is that net interchange out of the ERCOT area is positive while net interchange into the ERCOT area is negative.

Net Scheduled Interchange
The mutually prearranged intended net power flow on the ERCOT System's interconnections with other non-ERCOT Systems.

J

[Back to Top]

K

[Back to Top]

L

[Back to Top]

M

[Back to Top]

N

[Back to Top]

O

[Back to Top]

P

[Back to Top]

Q

[Back to Top]

R

[Back to Top]

Reserve Discount Factor (RDF)
A representation of the average amount of system wide capability that, for whatever reason, is historically undeliverable during periods of high system demand. The RDF will be verified by ERCOT and then approved by the Reliability and Operations Subcommittee (ROS).

S

[Back to Top]

T

[Back to Top]

Telemetry
Equipment for measuring a quantity (e.g., 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 VAr flow out of the bus and into the line is considered to be positive (+) flow.

(2) MW or VAr flow into the bus and out of the line is considered to be negative (-) flow.

Transmission Operator (TO)
Entity responsible for the safe and reliable operation of its own portion or designated portion of the ERCOT Transmission System. Every Transmission Service Provider (TSP) or Distribution Service Provider (DSP) in the ERCOT Region shall either register as a TO, or designate a TO as its representative and with the authority to act on its behalf.

U

[Back to Top]

V

[Back to Top]

W

[Back to Top]

X

[Back to Top]

Y

[Back to Top]

Z

[Back to Top]

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 power system. Instruction provided shall be in accordance with NERC Reliability Standards, the ERCOT 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 or blackouts;

(d) Operate the system as economically as possible within continually changing operating constraints; 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 and Load Resources shall participate in 32 hours per year of training and drills on system emergencies. QSE operators who do not represent Generation 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. 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. 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. The Operator Training Seminar should present information to maintain the consistency of operators across all of the ERCOT Region.

(2) The seminar provides a forum for QSE, TO, Transmission Service Provider (TSP) or Distribution Service Provider (DSP) and other ERCOT System Operators to meet and analyze common topics and issues as well as participate in formal training sessions.

1.5.4 ERCOT Severe Weather Drill

ERCOT shall conduct a severe weather drill each year. This drill will be used to test the scheduling and communication functions of the primary and/or backup centers and train operators in emergency procedures. Operators for QSEs that provide Ancillary Services and TOs are required to participate in the drill. ERCOT will appoint an ERCOT drill coordinator who, with assistance from the Operations Working Group (OWG), will develop and coordinate the annual severe weather drill. The OWG will review and critique the results of completed severe weather drills to ensure effectiveness and recommend changes as necessary. The Texas Regional Entity (TRE) will verify and report Entity participation to the Reliability and Operations Subcommittee (ROS).

1.5.5 Criteria For The Selection Of Operators

To be selected as operators, candidates should be capable of directing other personnel in their own organization and, at the same time, work harmoniously with the ERCOT System Operators and other Entities' operators. In addition, they must have a high intellectual ability, above average reasoning, mathematical ability, well-developed communication skills and reasonable mechanical aptitude. To ensure compliance with these criteria, a screening and selection procedure must be considered for prospective Operators. This procedure should include the following:

(a) Evaluation against a detailed job description;

(b) Analysis of the candidate's past work record to determine character, reputation, and previous experience;

(c) In-depth interview with each candidate; and

(d) Evaluation of intelligence, logic, mathematical, and communication skills along with psychological fitness.

1.5.6 Training Practices

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.

ERCOT Nodal Operating Guides

Section 2: System Operations and Control Requirements

December 1, 2009

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

PUBLIC

*** All References to Protocols and Operating Guides throughout this document are to Nodal Protocols and Nodal Operating Guides*

2 SYSTEM OPERATIONS AND CONTROL REQUIREMENTS

2.1 Operational Duties

The duties of ERCOT are described in relevant sections of the ERCOT 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:

(1) 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 transmission grid reliability studies, including those related to generation and load interconnection responsibilities;

(c) Review all Outages of generating units 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;

(e) Withdraw approval of a scheduled Outage if unable to meet the applicable reliability standards 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 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.

(2) Operate energy and Ancillary Service markets:

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

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

(c) Administer the RUC processes;

(d) If necessary, administer a Supplemental Ancillary Service Market (SASM); and

(e) Administer a Real-Time energy market using Security-Constrained Economic Dispatch (SCED).

(3) Supervise the ERCOT System to meet NERC criteria:

(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 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.

(4) Collect and Disseminate Information:

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

(b) Provide relevant operational information to Market Participants over the ERCOT 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) and/or NERC as required;

(e) Submit reports to DOE and/or NERC 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) make changes to assure 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 and interchange 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 ERCOT 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) Unless an Emergency Condition has been declared by ERCOT, the ERCOT System shall be operated in such a manner that the occurrence of a Credible Single Contingency will not cause any of the following conditions:

(a) Uncontrolled breakup of the transmission system;

(b) Loading of Transmission Facilities above defined Emergency Ratings that can not be eliminated in time to prevent damage or failure following the loss through execution of specific, predefined operating procedures;

(c) Transmission voltage levels outside system design limits that can not be corrected through execution of specific, predefined operating procedures before voltage instability or collapse occurs; or

(d) Customer Outages, except for high set interruptible and radially served loads.

2.2.3 Response to Transient Voltage Disturbance

QSE generators 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 and Responsive Reserve energy as necessary in accordance with Protocol Section 6.5.7.6, Load Frequency Control, to meet North American Electric Reliability Corporation (NERC) Standards. ERCOT shall purchase sufficient regulation Resources 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 unit Outages and load forecast error, to expect operation of 95% of hours without deploying Responsive Reserve Service.

(3) QSEs shall use Automatic Generation Control (AGC) to direct the output of generation facilities providing Regulation and Responsive Reserve Service.

2.2.4.1 Maintenance and Verification

Each provider of Regulation and/or Responsive Reserve 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

If a QSE providing Regulation Services or Responsive Reserve 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. Possible ERCOT actions include opening a Supplemental Ancillary Service Market (SASM) per Protocol Section 6.4.8.2, Supplemental Ancillary Service Market, for the period of anticipated loss.

2.2.4.3 ERCOT Loss of AGC

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.

2.2.5 Automatic Voltage Regulators

(1) Generator Automatic Voltage Regulators (AVR) will be kept in service when the unit is in normal operating range, set to regulate Generation Resource terminal voltage. Generation Entities shall notify their QSEs, who in turn will notify ERCOT per Protocol Section 3.15.3, QSE Responsibilities Related to Voltage Support, when a voltage regulator is unavailable due to maintenance or failure and when the AVR returns to normal operation. ERCOT is responsible for notifying the appropriate TO of such AVR status changes. QSEs shall supply AVR status logs to ERCOT upon request per Protocol Section 6.5.5.1, Changes in Resource Status.

(2) Generation Entities shall conduct performance tests on AVRs or verify AVR performance through comparison with operational data a minimum of every five years per item (5) of Protocol Section 8.1.2.2.5, Reactive Supply from Generation Resources Providing Voltage Support Service (VSS), or if equipment characteristics are knowingly modified, within 30 days of the modification. The test reports should include the minimum and maximum excitation limiters, volts/hertz settings, gain and time constants, type of voltage regulator control function, date tested, and voltage regulator control setting.

(3) Generation Entities shall verify excitation systems model data upon initial installation, within 30 days of performance modifications, and a minimum of five years thereafter.

(4) Generation Resource AVR modeling information required in the ERCOT Planning Criteria shall be determined from actual Generation Resource testing described in the Operating Guides. Within 30 days of ERCOT's request, the results of the latest test performed shall be supplied to ERCOT and the Transmission Service Provider (TSP).

2.2.6 Power System Stabilizers

(1) Generation Resources with a Power System Stabilizer (PSS) for which settings have been determined by the Generation Resource or by ERCOT, shall keep the PSS in service when the Generation Resource is in normal operating range. Generation Entities shall notify their QSEs, who in turn will notify ERCOT of the circumstances when a stabilizer is unavailable due to maintenance or failure and when the stabilizer returns to normal operation. ERCOT is responsible for notifying the appropriate TO of such PSS status changes. QSEs shall supply PSS status logs to ERCOT upon request per Protocol Section 6.5.5.1, Changes in Resource Status.

(2) Synchronous Generation Resources greater than 10 MW installed after January 1, 2008 shall install a PSS and place the PSS in service within 180 days after unit commissioning. The Generation Resource shall determine 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 for adequate damping during PSS commissioning. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of commissioning.

(3) For synchronous Generation Resources greater than 10 MW installed on or before January 1, 2008.

(a) If a PSS has been installed for the Generation Resource, the Generation Resource may voluntarily determine settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz, subject to the following limitation. The PSS on any Generation Resource for which PSS settings had been determined and the PSS had been commissioned prior to January 1, 2008 must remain in-service with the previously determined settings, unless the Generation Resource is directed by ERCOT to modify the settings. The PSS settings shall be tested and tuned for adequate damping prior to placing the PSS on line. The Generation Resource shall notify ERCOT:

(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.

If the PSS has been or will be placed in-service, the Generation Resource will provide the stabilizer settings to ERCOT and the TSP within 30 days of commissioning.

(b) If a PSS has been installed but has not been placed in service, ERCOT may determine and provide the Generation Resource with recommended PSS settings.

Within 180 days of ERCOT providing recommended PSS settings to the Generation Resource or at a time mutually agreeable to ERCOT and the Generation Resource, the Generation Resource shall test and tune the PSS to dampen modes with oscillations within the range of 0.2 to 2 Hz or as specified by ERCOT, and place the PSS in-service. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of commissioning.

(4) If an excitation system on a synchronous Generation Resource greater than or equal to 10 MW is upgraded or replaced after January 1, 2008, the Generation Resource shall install a PSS, determine PSS settings to dampen modes with oscillations within the range of 0.2 to 2.0 Hz, and place the PSS in-service. The settings shall be tested and tuned for adequate damping during excitation system commissioning. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of commissioning.

(5) If ERCOT determines a change in PSS settings for a synchronous Generation Resource would improve overall system performance, ERCOT shall coordinate with the Generation Resource owner to determine appropriate settings. Within 180 days of determining appropriate settings, the Generation Resource owner shall test and tune the PSS to dampen modes with oscillations as requested by ERCOT and place the PSS in-service. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of commissioning.

(6) Generation Entities shall conduct performance tests on Power System Stabilizers which have settings or verify PSS performance through comparison with operational data at least every five years, or if equipment characteristics are knowingly modified, within 30 days of the modification.

(7) The results of the most recent PSS test shall be supplied to ERCOT and the TSP within 30 days of a request from ERCOT.

2.2.7 Turbine Speed Governors

(1) All governors must be placed in-service for all Generation Resources (except nuclear and wind) as soon as power is above the minimum operating limit, per Protocol Section 8.5.1.1, Governor in Service.

(2) Governor performance tests for mechanical hydraulic governors or electro-hydraulic governors shall be conducted at least every two years unless a written exception is obtained from ERCOT. The test forms are located in Section 8, Attachment C, Turbine Governor Speed Tests. Maintenance and tests on governors shall demonstrate calibration for operation with a 5% droop characteristic and dead band no greater than +/- 0.0.36 Hz.

(3) Elements other than poor governance maintenance that can contribute to poor governor response include:

(a) Governor dead band greater than the maximum intentional dead band is +/- 0.036 Hz.);

(b) Valve position limits;

(c) Blocked governor operation;

(d) Control mode;

(e) Adjustable rates or limits;

(f) Boiler/turbine coordinated control or set point control action; and

(g) Automated “reset” or similar control action of the turbine’s MW set point.

(4) Every attempt should be made to minimize the effects of the elements listed in item (3) above on the governor operation for the duration of all frequency deviations. Each QSE should monitor its units to verify that these elements do not contribute to a governor droop characteristic greater than 5%.

2.2.8 Performance/Disturbance/Compliance Analysis

(1) Performance/Disturbance/Compliance analysis shall be performed by ERCOT for the purpose of ensuring conformance to the Protocols. All generators except wind and nuclear powered must respond to frequency disturbances with a governor droop of 5% or less unless limited by a High Sustained Limit (HSL) or other limits filed with ERCOT including duct burning on Combined-Cycle units.

(2) ERCOT shall make a regular report on selected system disturbances, documenting the response of individual QSEs, together with a summary. In addition, Resource Entities, QSEs, and individual members of the Performance Disturbance Compliance Working Group (PDCWG) are encouraged to work within their respective companies to enhance the performance of individual generating resources control systems through application of the results of the PDCWG studies.

(3) To ensure compliance and improved performance, the Texas Regional Entity (TRE) shall communicate with the Market Participants that are not meeting the current performance requirements.

(4) As necessary, a Contingency Reserve Adjustment (CRA) as defined by NERC Reliability Standards, will be calculated by the PDCWG and submitted to the Reliability and Operations Subcommittee (ROS) for review and approval. ERCOT will include the CRA in the daily Ancillary Service plan.

2.2.9 Time Error and Time Synchronization

2.2.9.1 Time Error

Sustained frequency deviations from scheduled frequency result in time error. Time error will be monitored and controlled in ERCOT as follows:

(1) Time Error Monitoring - ERCOT will monitor accumulated time error and initiate time corrections. The instantaneous time error is available to all ERCOT QSEs on the ERCOT MIS Public Area. When time error is equal to or greater than ±3 seconds, ERCOT may initiate a time correction. The correction may end when the error is less than ±0.5 seconds, or when system events mandate termination. The time correction may be postponed if it is

determined that load patterns in the immediate future will result in the desired time correction; however, at no time should the accumulated time error be allowed to exceed 5 seconds.

(2) Time Error Correction - When a time correction is necessary, ERCOT will adjust scheduled frequency by arranging for more or less Resources by implementing a frequency offset. Information will be communicated via hotline call to all QSEs, which will include the frequency offset (-.02 Hz for fast and +.02 Hz for slow) and the start time. A time correction may be terminated after five hours, or after any hour without a 0.5 second error reduction. ERCOT will provide adequate notice of the ending of a time correction to all QSEs in the ERCOT Region.

2.2.9.2 Time Synchronization

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**.**

2.3 Ancillary Services

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) ***Reference: Protocol Section 2, Definitions and Acronyms***	Resource capacity provided by a Qualified Scheduling Entity (QSE) from a specific Resource to control frequency within the system which is controlled second by second, normally by an Automatic Generation Control (AGC) System.	a. Reg-Down is a deployment to increase or decrease generation at a level below the Resource's base point in response to a change in system frequency. b. Reg-Up is a deployment to increase or decrease generation at a level above the Resource's base point in response to a change in system frequency.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Reg-Down and Reg-Up (for Load Resource) ***Reference: Protocol Section 2, Definitions and Acronyms***	Load Resource capacity provided by a QSE from a specific Load Resource to control frequency within the system.	a. Reg-Down is a deployment to increase or decrease Load as deployed within its Ancillary Service Schedule for Reg-Down below the Load Resource's Maximum Power Consumption (MPC) limit in response to a change in system frequency. b. Reg-Up is a deployment to increase or decrease Load as deployed within its Ancillary Service Schedule for Reg-Up above the Low Power Consumption (LPC) limit in response to a change in system frequency.
Responsive Reserve (RRS) Service ***Reference: Protocol Section 2, Definitions and Acronyms***	Operating reserves on Generation Resources and Load Resources maintained by ERCOT to help control the frequency of the system. RRS on Generation Resources and controllable Load Resources that are qualified to provide regulation can also be used as a backup regulation service and 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 for back-up regulation; and c. As ordered by ERCOT Operator during EEA or other emergencies.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Non-Spinning Reserve (Non-Spin) Service ***Reference: Protocol Section 2, Definitions and Acronyms***	a. Off-Line Generation Resource capacity, or reserved capacity from On-Line Generation Resources, capable of being ramped to a specified output level within 30 minutes, and operating at a specified output for at least one hour b. Load Resources that are capable of being interrupted within 30 minutes and remaining interrupted for at least one hour.	Deployed in response to loss-of-Resource contingencies, load forecasting error, or other contingency events on the system. As described in Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.
Voltage Support ***Reference: Protocol Section 3.15, Voltage Support***	Reactive capability of a Generation Resource that is required to maintain transmission and distribution voltages on the ERCOT Transmission Grid within acceptable limits. All Generation Resources with a gross generating unit rating greater than 20 MVA shall provide Voltage Support Service (VSS).	Direct the scheduling of VSS by providing Voltage Profiles at the high voltage side of generator busses. The Generation Resource is obligated to maintain the published voltage profile within its Corrected Unit Reactive Limit (CURL).
Black Start Service ***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 blackout.	Provide emergency Dispatch Instructions to begin restoration to a secure operating state after a total or partial blackout.
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 (RRS)

2.3.1.1 Obligation

ERCOT operating reserve requirements are more restrictive than North American Electric Corporation (NERC) Standards. The ERCOT Responsive Reserve obligation is a minimum of 2300 MW.

2.3.1.2 Additional Operational Details for Responsive Reserve Providers

(1) ERCOT shall specify the minimum amount of RRS provided by Generation Resources. QSE's Generation Resources providing RRS must be On-line and capable of ramping to the awarded output level within ten minutes of the notice to deploy energy, must be immediately responsive to system frequency, and must be able to maintain the scheduled level for the period of service commitment.

(2) RRS provided by a QSE shall meet the requirements as defined in item (5), Protocol Section 3.18, Resource Limits in Providing Ancillary Service.

(3) Load Resources providing RRS must be controlled by under-frequency relays for automatic interruption. For eligibility to participate as a RRS provider, reference Protocol Section 8.1.2.2.3, Responsive Reserve Service. Load Resources 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) 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 the ERCOT Operator.

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

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

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

(5) A Direct Current Tie (DC Tie) may be used as Responsive Spinning Reserve up to 30 MW subject to the following constraints:

(a) The tie shall respond with increased deliveries to ERCOT or decreased deliveries from ERCOT at a frequency of 59.9 Hz;

(b) The response rate will not be less than 30 MW per minute;

(c) The response delay will not exceed four seconds;

(d) The response will be retained until frequency has recovered to a level at or above 60.0 Hz or as directed by ERCOT;

(e) A QSE claiming DC Tie RRS must demonstrate the existence of contracts agreeing to provide the required response with the DC Tie operator; and

(f) A QSE claiming DC Tie RRS must have an agreement with the balancing authority on the opposite side of the DC Tie involved approving the amount and conditions.

(6) Hydro Unit(s) **–** Modes of RRS that will be counted:

(a) Synchronous condenser fast response mode **-** described in item (5), Protocol Section 3.18, Resource Limits in Providing Ancillary Service;

(b) Generation MW mode **-** For any hydro powered resource with a 5% droop setting operating as a generator, the amount of RRS provided may never be more than 20% of the High Sustained Limit (HSL);

(c) Synchronous Condenser on Under Frequency Relays in Megavar Supply Mode - A verbal dispatch from ERCOT is required to operate in this mode. However, during an under-frequency event, Vars are unloaded in no more than 30 seconds. Once unloaded, then Megawatts are delivered. Once deployed these units are frequency responsive;

(d) Synchronous Condenser Mode in “Manual” Dispatch Mode - Units will supply Megawatts based on operator action within the 10-minute Protocol requirement for supplying RRS. Once deployed these units are frequency responsive; and

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

2.3.2 Non-Spinning Reserve Service (Non-Spin)

2.3.2.1 Additional Operational Details for Non-Spinning Reserve Service (Non-Spin) Providers

(1) Non-Spinning Reserve Service (Non-Spin) Generating Resource providers 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 one hour, as specified in item (1)(a), Protocol Section 3.17.3, Non-Spinning Reserve Service.

(2) Non-Spin Load Resource providers must be capable of unloading within 30 minutes and remaining unloaded for at least one hour, as specified in item (1)(b), Protocol Section 3.17.3, Non-Spinning Reserve Service. Load Resources must not be fulfilling any other commitment from the capacity, including participation in ERCOT markets, self-generation, or other energy transactions.

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

(a) Register as a 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 Verbal Dispatch Instructions (VDIs) by ERCOT;

(e) Be telemetered through the QSE to ERCOT with the Load MW of each Load breaker, breaker status, and signals representing the Load Resource's MW response to instruction; and

(f) Be able to remain interrupted during an ERCOT deployment for a minimum of one hour up to a maximum of the hours of service awarded.

(4) To become and remain fully qualified as a provider of Non-Spin, the Load 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 Ancillary Services Monitoring Program

RESERVED

2.4 Outage Coordination

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 (RUC)

Reliability Unit Commitment (RUC) is a process to ensure that there is adequate Resource capacity and Ancillary Service capacity committed in the proper locations to serve ERCOT forecasted Load.

2.5.1 Criteria for Removing Contingencies from the RUC Analyses

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

(b) Contingency has been producing in Real-Time contingency results which cannot be eliminated or significantly improved by generation adjustment. ERCOT will study this type of contingency to determine if a Remedial Action Plan (RAP)/Mitigation Plan proposal is possible; and

(c) Contingency is known to produce a non-convergent contingency result which may cause the RUC processes to fail. ERCOT shall create a generic constraint if non-convergent case represents a voltage collapse.

2.6 Requirements for Under-Frequency Relaying

2.6.1 Automatic Firm Load Shedding

(1) At least 25% of the ERCOT System Load that is not equipped with high-set under-frequency relays shall be equipped at all times with provisions for automatic under-frequency load shedding. The under-frequency relays shall be set to provide Load relief as follows:

Frequency Threshold	Load Relief
59.3 Hz	5% of the ERCOT System Load (Total 5%)
58.9 Hz	An additional 10% of the ERCOT System Load (Total 15%)
58.5 Hz	An additional 10% of the ERCOT System Load (Total 25%)

(2) With the assistance of applicable Transmission Service Providers (TSPs), ERCOT will, prior to the peak each year, survey each Distribution Service Provider's (DSP's) compliance with the automatic Load shedding steps above, and report its findings to the Technical Advisory Committee (TAC). For minimum compliance, DSPs are obligated to meet the prescribed percent values at all times. It is not permitted to use rounding to meet the minimum. ERCOT will direct a review of the automatic firm Load shedding program whenever warranted by conditions. At a minimum, this review will follow the Reliability and Operations Subcommittee (ROS) directed dynamic simulations of automatic firm Load shedding conducted at five-year intervals beginning in the Summer of 2001.

(3) Additional under-frequency relays may be installed on Transmission Facilities with the approval of ERCOT provided the relays are set at 58.0 cycles 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.

(4) 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 of no more than 30 cycles. T otal time from the time when frequency first reaches one of the values specified above to the time Load is interrupted should be no more than 40 cycles, including all relay

and breaker operating times. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

(5) If a loss of Load occurs due to the operation of under-frequency relays, a Transmission Operator (TO) designated by a DSP to shed Load 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 by a TO 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. TOs, in coordination with DSPs, shall exercise extreme caution in restoring Load so that the capability limits of generating units and transmission lines are not exceeded.

(6) Whenever possible, TOs and DSPs shall not manually drop Load connected to under-frequency relays during the implementation of Level 3 of the Energy Emergency Alert (EEA).

2.6.2 Generators

(1) If under-frequency relays are installed, these relays shall be set such that the automatic removal of individual generating units from the ERCOT System meets 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) No prearranged instruction that conflicts with the above limits will be given for the manual removal of an otherwise operable generating unit. This Operating Guide is not intended to conflict with the plant operator's responsibility to protect generating units from potentially damaging operating conditions. While this Operating Guide does not address the removal of generating units for frequency deviations above 60 Hz, it is realized that the generating unit operating restrictions below 60 Hz apply equally to operation of a generating unit above 60 Hz.

2.7 System Voltage Profile

2.7.1 Introduction

(1) The system Voltage Profile is a predetermined distribution of desired nominal voltage set points across the ERCOT Region.

(2) ERCOT shall coordinate and conduct studies with the Transmission Service Providers (TSPs) to determine the normally desired Voltage Profile for all Generation Resource busses in the ERCOT Region as specified in item (1), Protocol Section 3.15, Voltage Support as published on the ERCOT Market Information System (MIS) Secure Area.

(3) ERCOT shall establish and update Voltage Profiles at points of interconnection of Generation Resources to maintain system voltages within established limits.

2.7.2 Maintaining Voltage Profile

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

(1) Operations Engineering

(a) 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

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

(2) Coordination

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

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

(c) Voltage limits shall not be violated during all normal and first contingency conditions; and

(d) 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.

(3) Notification

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

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

(4) Response

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

(5) Monitoring

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

(6) Controls

(a) ERCOT must be aware of the locations of available reactive capability;

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

(c) Controls to maintain Voltage Profiles may include but are not limited to Capacitor switching, reactor switching, auto-transformer tap changing, generator reactive dispatch, transmission line switching, and Load shedding.

(7) Documentation

(a) 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.

(8) Emergency or Abnormal Conditions

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

(b) 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

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

2.7.3 Special Consideration for Nuclear Power Plants

In all planning studies and Real-Time operations, ERCOT and TOs shall maintain the switchyard voltage at each nuclear power plant at a nominal value that does not violate its licensing basis with the Nuclear Regulatory Commission. 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 and 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.

2.7.4 Reactive Considerations for Generation Resources

2.7.4.1 Maintaining System Voltage

(1) ERCOT will maintain a performance log of QSEs acknowledgements of Dispatch Instructions concerning scheduled voltage or scheduled Reactive output requests. QSEs responding in less than two minutes from the time of issuance of such requests shall be deemed satisfactory.

(2) ERCOT shall monitor the Automatic Voltage Regulator (AVR), as required in Protocol Section 6.5.5.1, Changes in Resource Status, to assure that it is on and operating automatically at least 98% of the time in which the QSE is providing the Reactive Power supply from Generation Resources required to provide Voltage Support Service (VSS). The percentage is calculated as: Time (AVR is on while providing Service) / (Total Time Providing Services) (100%).

(3) Except under Force Majeure conditions or ERCOT-permitted operation of the generating unit, failure of a Generation Resource required to provide VSS to provide either leading or lagging reactive up to the required capability of the unit upon request from a TO or ERCOT may, at the discretion of ERCOT, be reported to the Texas Regional Entity.

(4) Except under Force Majeure conditions or ERCOT-permitted operation of the generating unit, if a Generation Resource required to provide VSS fails to maintain transmission system voltage at the point of interconnection with the TSP within 2% of the voltage profile while operating at less than the maximum reactive capability of the generating unit, ERCOT may, at its discretion, report this to the Texas Regional Entity.

(5) The Texas Regional Entity will investigate claims of alleged non-compliance and Force Majeure conditions, and address confirmed non-compliance situations. The Texas Regional Entity will advise the Generation Resource, its QSE, ERCOT, and the TSP planning and operating staffs of the results of such investigations.

2.7.4.2 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 MIS Secure Area and must be provided in accordance with the Network Operations Model Change Request (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) From a modeling perspective, ERCOT shall work with the Market Participants to ensure that the advanced application tool(s) voltage/reactive control methodology reflects actual field operation to the extent practicable.

2.7.4.3 Unit Dispatch Beyond the Corrected Unit Reactive Limit (CURL) or Unit Reactive Limit (URL)

Each generator shall respond to ERCOT instructed voltage control, including exceeding its Corrected Unit Reactive Limit (CURL) or Unit Reactive Limit (URL). For multi-generator busses, ERCOT shall not instruct any single generator to operate beyond its CURL or URL until all generators 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 (DC 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.

2.8.1 Inadvertent Interchange Management

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. Accounting / payback will be handled according to North American Electric Reliability Corporation (NERC) Standards. All inadvertent energy is placed in an inadvertent payback account to be paid back in kind.

ERCOT Nodal Operating Guides

Section 3: Resource Testing and Qualification Procedures

August 1, 2010

***(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections*)**

*** All References to Protocols and Operating Guides throughout this document are to Nodal Protocols and Nodal Operating Guides*

3 RESOURCE TESTING AND QUALIFICATION PROCEDURES

3.1 System Control Interfaces with ERCOT

3.1.1 Introduction

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.

3.1.2 Compliance with Dispatch Instructions

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.

3.2 Qualified Scheduling Entities (QSEs)

3.2.1 Operating Obligations

(1) A Qualified Scheduling Entity (QSE) shall maintain a 24x7 scheduling center with qualified personnel with the authority to commit and bind the QSE. QSEs shall communicate with ERCOT for the purpose of meeting their obligations specified in the ERCOT Protocols and these Operating Guides. Each QSE shall designate an Authorized Representative as defined in Protocol Section 2.1, Definitions.

(2) Each QSE shall submit to ERCOT, by March 15 of each year, a written back-up control plan to continue operation in the event the QSE's scheduling center becomes inoperable. Back-up control plans shall be submitted to ERCOT via secured webmail. 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 Load and Generation Resource status 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 TSP of equipment changes that affect the reactive capability of an operating Generation Resource.

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

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:

(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 Special Protection Systems (SPS), Remedial Action Plans (RAPs) 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 and Compliance. 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, Non-Compliance.

(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 shall conform to the requirements of the ERCOT Protocols, North American Electric Reliability Corporation (NERC) Reliability Standards and these Operating Guides. Per Protocol Section, 3.7.1.1, Generation Resource Parameters, Protocol Section 3.7.1.2, Load Resource Parameters, and Protocol Section 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 and Load Resource.

(2) Per Protocol Section 3.10.7.1.4, Transmission and Generation Resource Step-Up Transformers, Resource Entities will provide information on step-up transformers to TSPs.

(3) Per Protocol Section 3.10.7.4, Telemetry Criteria, Protocol Section 6.5.5.2, Operational Data Requirements to ERCOT, and Protocol Section 8, Performance Monitoring and Compliance, 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 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.

(b) Any such changes that decrease the reactive capability of the Generation Resource below the required level must be approved by ERCOT prior to implementation;

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

(d) As soon as practicable when a Generation Resource trips off line due to voltage or reactive problems.

(5) When scheduled to ERCOT, Resource Entities shall be staffed or monitored 24 hours per day, by personnel capable of making operating decisions. Each Resource Entity shall designate an Authorized Representative as defined in Protocol Section 2, Definitions and Acronyms. This applies to all:

(a) Generation Resources 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 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 per 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 8.1.2.2, General Capacity Testing Requirements, requiring seasonal unit capability 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 generating unit via both email and surface mail. 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 generating 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 generating Resource is not operated and included in a QSE Current Operating Plan (COP) after the notification of the Protocols violation, then ERCOT shall not disqualify the Ancillary Service provider unless or until the generating Resource is operated and included in the COP that might be depended upon for Ancillary Services.

(4) In the context of generation testing requirements; seasons shall be defined as follows:

(a) Summer (May 15 – September 15)

(b) Fall (September 16 – November 30)

(c) Winter (December 1 – February 28)

(d) Spring (March 1 – May 14)

3.3.2 Unit Reactive Capability Requirements

3.3.2.1 Corrected Unit Reactive Limits (CURL)

The reactive capability curve 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 may be produced 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 will use for their studies. ERCOT Operations, after reviewing the updated curves and checking them for reasonableness, will forward copies to the Steady State Working Group (SSWG). The SSWG members shall have ten Business Days to provide ERCOT Operations any comments regarding updated curves. If appropriate, the SSWG shall use the updated curves in modeling such capability in the ERCOT transmission planning cases. If ERCOT finds the submitted CURL unreasonable, ERCOT will follow Section 3.5, ERCOT Implementation.

3.3.2.2 Non-Coordinated Reactive Testing

(1) The QSE representing the generating unit shall give ERCOT at least two hours advance notice prior to the start of the test. ERCOT shall notify the host TO prior to the test. ERCOT retains the right to cancel the reactive test if ERCOT believes, in its sole judgment, that conducting the test at the requested time could jeopardize the reliability of the ERCOT System. For example, ERCOT can cancel a requested leading capability test during a time when system voltages are low or expected to be low due to factors such as high import power levels, transmission line Outages, capacitor bank Outages, or generating unit Outages or exciter limitations.

(2) It is recommended, but not required, that tests to verify maximum lagging reactive capability shall be conducted during times when ERCOT System Loads are typically high, such as during the months of May through September, but not necessarily at the time of system peak. ERCOT has the authority to not allow a reactive capability test to be conducted if it believes system conditions at the requested time of the test are unfavorable. Units being tested shall be operating at or above 95% of net dependable real power (MW) output. If the unit being tested is unable to achieve adequate lagging reactive capability per the CURL, the unit, at its discretion, may utilize the capability of another unit in the same plant to offset (take in VArs) the lagging test that is under way. This circulation of VArs must leave the high side of the Generator Step Up (GSU) of the unit being tested and flow through the GSU of the unit taking in the VArs. Under no circumstances shall VArs be circulated between units on the same low side bus.

(3) It is recommended, but not required, that tests to verify maximum leading reactive capability be conducted during times when ERCOT System Loads are typically low, during the months of October through April. Units being tested shall be operating at a real power (MW) output representative of its usual loading during such light Load periods. ERCOT

has the authority to not allow a reactive capability test to be conducted if it believes system conditions at the requested time of the test are unfavorable.

(4) The Resource Entity shall measure the tested reactive capability on the low side of the generator terminals. The reading recorded shall represent the net MVAR output of the generator and shall have the unit's auxiliary reactive consumption deducted from the generator's gross reactive output at the machine's terminals. Additionally, the tested reactive capability shall be measured at the high side of the GSU transformer if metering is available. If metering is not available at the high side, the Resource Entity shall calculate the reactive capability at the high side. Both high side and generator terminal 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 fields shown on the form in the MIS shall be completed in order for a submittal to be considered complete by ERCOT.

(5) The QSE representing a generating unit shall be responsible for scheduling reactive verification tests in accordance with the conditions outlined above. If ERCOT does not issue an alternative reactive testing interval, the resource shall complete a reactive qualification test at least every two years.

(6) ERCOT shall have the option to waive the requirement to test and verify the maximum leading reactive capability of any generating unit that seldom runs during such light Load periods. The granting of such a waiver shall be effective for two years. Initial test results, as provided by ERCOT in the Resource Asset Registration Form (RARF) and the two-year reactive test results beginning December 1, 2008 shall be posted to the MIS Certified Area. Initial test results and two-year reactive test results conducted prior to December 1, 2008 shall not need to be resubmitted to the MIS and will remain on file with ERCOT in the original hard copy format.

(7) The minimum duration for any reactive verification test, leading or lagging, is 15 minutes. The CURL should be posted in the Resource Entities control room, where the tests are conducted, at the QSE's Real-Time/generation dispatch desk, and copies should be provided to ERCOT Operations. During any test, the unit must maintain its generator cooling system at normal operating level. Tests will be conducted to produce MVArs at a level not less than 90% of the amount indicated by the existing reactive capability curve (original manufacturer's unit reactive capability curve, or the most recent CURL).

(8) The QSE representing a generating unit shall be responsible for the timely and accurate reporting of test results to ERCOT. The QSE representing a generating unit shall be responsible for the timely submittal to ERCOT of an updated CURL reflecting any known changes in the reactive output of the unit. A QSE must properly complete all required data fields in the MIS Certified Area for a test to be considered valid.

3.3.2.3 Coordinated Reactive Testing

(1) "Coordinated Testing" is the testing of a generator's reactive capability to verify the generating unit's most current CURL. The verification test will be a coordinated effort between the Resource Entity, the Resource Entity's QSE, the TO which the Resource Entity

is connected, and ERCOT Operations. Coordinated Testing is at the option of the Resource Entity. Coordinated Testing can be ordered by ERCOT if a retest is required.

(2) The Resource Entity requesting to perform a Coordinated Test will provide ERCOT Operations and the TO with a minimum of 48 hours notice of the proposed test date. Requests shall be made between 0800 and 1700 on Business Days. Upon receipt of a request for test, ERCOT Operations and the TO will evaluate the expected conditions and determine whether transmission system conditions conducive to a valid test can be created through coordinated network switching, modification of the generation reactive dispatch of nearby generating units, or by some other means. Having established that suitable transmission system conditions exist or can be created, ERCOT Operations, and the TO shall confirm with the Resource Entity and the QSE the agreed upon test time and date or a rejection of the test time and date within 24 hours of the receipt of the request.

(3) The Coordinated Test shall begin and end within the standard work day (nominally 0800 to 1700). Since leading tests will often occur in off-peak periods, the coordinated leading test shall begin and end at times agreed to by ERCOT, the TO, QSE and Resource Entity. The minimum duration for any reactive verification test, leading or lagging, is 15 minutes. The CURL should be provided to ERCOT Operations and posted in the Resource Entity's control room and at the QSE's Real-Time/generation dispatch desk. The testing period shall be scheduled such that sufficient time is given for any transmission switching. During the test, the QSE operator shall be in communication with the TO in order to coordinate the reactive output of adjacent units, capacitor switching, reactor switching, and any other activity needed to perform the scheduled reactive test accurately.

(4) Lagging Reactive Tests - Generating units shall be tested to verify lagging reactive capability at or above 95% of net dependable real power output as indicated on the CURL. Maximum lagging capability is most likely to be needed during times when ERCOT System Loads are typically high, and transmission system voltages are relatively low, such as during the months of May through September. ERCOT has the authority to not allow a reactive capability test to be conducted if it believes the system conditions at the requested time of the test are unfavorable. The transmission voltage at the switchyard to which the generating unit is connected should be at or below the ERCOT currently scheduled voltage prior to starting the test. If the unit being tested is unable to achieve adequate lagging reactive capability per the CURL, the unit, at its discretion, may utilize the capability of another unit in the same plant to offset (take in VArs) the lagging test that is under way. This circulation of VArs must leave the high side of the GSU of the unit being tested and flow through the GSU of the unit taking in the VArs. Under no circumstances shall VArs be circulated between units on the same low side bus.

(5) Leading Reactive Tests - Generating units shall be tested to verify leading reactive capability at a MW loading level representative of expected generating unit MW loading during minimum Load conditions as indicated on the CURL. Maximum leading capability is most likely to be needed when ERCOT System Loads are typically light and transmission system voltages are relatively high, specifically during the months of October through April. ERCOT has the authority to not allow a reactive capability test to be conducted if it believes the system conditions at the requested time of the test are unfavorable. The transmission voltage at the switchyard to which the generating unit is connected should be at or above the ERCOT currently scheduled voltage prior to starting the test. At ERCOT's sole discretion,

the requirement to test leading capability may be waived for peaking generating units which seldom, if ever, run during light Load conditions.

(6) The Resource Entity shall measure the tested reactive capability at the generator terminals. The reading recorded shall represent the net MVAR output of the generator and shall have the unit's auxiliary reactive consumption deducted from the generator's gross reactive output at the machine's terminals. Additionally, the tested reactive capability shall be measured at the high side of the GSU transformer if metering is available. If metering is not available at the high side, the Resource Entity shall calculate the reactive capability at the high side. Both high side and generator terminal values are required for proper submittal of the test results.

(7) The QSE representing a generating unit shall be responsible for scheduling reactive tests in accordance with the conditions outlined above, and for the timely and accurate reporting of test results to ERCOT. All test documents (the CURL and the CURL with the test point indicated) shall be submitted by the Resource Entity's QSE. The Resource Entity must properly complete all required data fields in the MIS Certified Area for a test to be considered complete.

3.4 Load Resource Testing Requirement

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 specified in these Operating Guides. 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 noncompliance. 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 Staff to determine 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 Staff to determine if test results fall within 90% of Corrected Unit Reactive Limit (CURL) expectation. If test results are less than 90% of CURL expectation, ERCOT shall have the right to either order the Resource Entity to produce a new CURL, or to order a re-test of the unit.

(3) Reactive test results shall be reviewed by ERCOT Staff against the most recent CURL for the unit. If unit reactive capability appears to be limited to less than 90% of CURL by unit controls or relays, ERCOT staff 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) CURL data validated by test, or any new CURL produced by a Resource Entity in response to new operating limits, shall be implemented by ERCOT Staff in its operational model

within two weeks of receipt and resolution of the data. ERCOT Staff will provide such data to the Steady State Working Group (SSWG) after validation by ERCOT Operations for implementation in the planning model.

3.6 Enforcement of Unit Reactive Capability Testing

Details of the enforcement for reactive capability testing can be found in the Compliance Template located on the ERCOT Market Information System (MIS) Public Area.

3.7 Enforcement of Automatic Voltage Regulator (AVR) Testing

Details of the enforcement for reactive capability testing can be found in the Compliance Template located on the ERCOT MIS Public Area.

3.8 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, ERCOT Protocols and Operating Guides.

(2) TSPs shall designate an Authorized Representative as defined in Protocol Section 2, Definitions and Acronyms.

(3) Each TSP, at its own expense, may obtain Operating Period data from ERCOT.

3.9 Transmission Operators

(1) Transmission Operators (TOs) shall follow ERCOT instructions related to ERCOT responsibilities:

(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;

(c) Managing Voltage Profiles established by ERCOT. TOs, under the direction of ERCOT, will coordinate Transmission Service Provider (TSP) static device switching with Qualified Scheduling Entity (QSE) dynamic reactive device operation. Static reactive devices will be brought On-Line before predicted daily maximum Load growth or 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. ERCOT will coordinate Automatic Voltage Regulator (AVR), dynamic and static reactive device Outages to ensure adequate reactive reserves are maintained; and

(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.

(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 Criteria;

(c) Operate and manage Transmission Facilities between energy sources and the point of delivery;

(d) Coordinate emergency communications between a represented TSP 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 basis) 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;

(j) Maintain operational metering; and

(k) Implement Black Start.

(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. The TO shallrequest 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.

3.9.1 Transmission Owner Responsibility for a Vegetation Management Program

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.

3.9.2 NERC Requirements for Reporting Vegetation-Related Line Outages

In ERCOT, transmission owners shall report vegetation-related 345 kV transmission line Outages for each calendar month to their respective TOs. TOs shall report these monthly Outage statistics to the Texas Regional Entity (TRE) by the 20^{th} of the following month. The TRE shall report results to NERC. Details of the NERC requirements, including reporting exceptions, can be found in the vegetation management program template located on the TRE Web Page.

3.9.3 ERCOT Requirements for Reporting Sabotage Information

(1) A TSP, QSE, or any ERCOT Entity shall inform ERCOT when experiencing disturbances or unusual occurrences suspected or determined to be caused by sabotage as described in NERC Reliability Standard, Sabotage Reporting. ERCOT Entities shall have procedures for the recognition of sabotage events on its facilities and multi-site sabotage.

(2) ERCOT shall inform NERC and governmental agencies of the threat of sabotage in accordance with current laws and regulations. ERCOT may inform other TSPs or QSEs of the event(s), if, in the opinion of ERCOT, the situation impacts ERCOT reliability.

3.9.4 Responsibility for Equipment Ratings

(1) TSPs are responsible for determining the rating of their facilities. Technical limits established for the operation of Transmission Elements and associated equipment shall be applied consistently in engineering and planning studies, Real-Time security analyses, and operator actions.

(2) TSPs shall provide ERCOT with three nominal Transmission Element Ratings:

(a) Normal Rating: Represents the continuous MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating indefinitely without damage, or violation of National Electrical Safety Code (NESC) clearances.

(b) Emergency Rating: Represents the two-hour MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The Transmission Element can operate at this rating for two hours without violation of NESC clearances or equipment failure.

(c) 15-Minute Rating: Represents the 15 minute MVA rating of a Transmission Element, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature and with a step increase from a prior loading of 90% of the Normal Rating. The Transmission Element can operate at this rating for 15 minutes, assuming its pre-contingency loading was 90% of the Normal Rating limit at the applicable ambient temperature, without violation of NESC clearances or equipment failure. This rating takes advantage of the time delay associated with heating of a conductor or transformer following a sudden increase in current.

(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 a valid Remedial Action Plan (RAP) is unavailable to unload the Transmission Element post contingency or the pre-contingency loading is greater than 90% of the Normal Rating, ERCOT shall enforce pre-contingency system operating limit(s) to control the post contingency loading of the Transmission Element 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 a RAP is documented at ERCOT to relieve the loading on the Transmission Element within 15 minutes, ERCOT shall enforce pre-contingency system operating limit(s) to control the post contingency loading of the Transmission Element to levels below the 15-Minute Rating. The enforcement shall be implemented in a manner such that the post-contingency loading will be at, or below, Emergency Rating within 15 minutes.

(d) ERCOT shall use best efforts to restore all Transmission Element to within Normal Ratings as soon as practicable, based on Good Utility Practice.

ERCOT Nodal Operating Guides

Section 4: Emergency Operation

June 1, 2010

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

---

4 Emergency Operation

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 Notices, 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 emergency 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 Emergency Notifications

4.2.1 Operating Condition Notice

(1) An Operating Condition Notice (OCN) will be issued by ERCOT in accordance with Protocol Section 6.5.9.3.1, Operating Condition Notice. OCNs are for communication only, and ERCOT exercises no extra authority with the issuance of this type of notice.

(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 all TOs and QSEs and post the message electronically to the ERCOT Market Information System (MIS) Secure Area. When an OCN is issued, it does not place ERCOT in an emergency operating state. QSEs should notify appropriate Resources, Retail Electric Providers (REPs) and Load Serving Entities (LSEs). TOs should notify their represented Transmission Service Providers (TSPs) as appropriate.

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 response to impending severe 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 all TOs and QSEs and shall post the message electronically to the MIS Secure Area. When an Advisory is issued, it does not place ERCOT in an emergency operating state. QSEs shall notify appropriate Resources, REPs and LSEs of Advisories. TOs should notify their represented TSPs as appropriate 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 insecure operating state exists or is 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 a non-critical element can not be rectified by congestion management methods, including Remedial Action Plans (see Section 4.3.1, Remedial Action Plans (RAP)), or mitigation plans, ERCOT shall issue a Watch. A “non-critical element” is one whose loss will not result in an uncontrolled separation of cascading Outages or large scale service disruptions to Load or overload of a critical transmission element.

(4) ERCOT shall provide verbal notice of the Watch to all TOs and QSEs and shall post the message electronically to the MIS Secure Area. While operating under a Watch, ERCOT is operating in an emergency operating state. QSEs shall notify appropriate Resources, REPs and LSEs. TOs shall notify their represented TSPs.

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. ERCOT is considered to be in an insecure state whenever 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 critical Transmission Element, and no timely solution is obtainable from the market.

(2) ERCOT shall provide verbal notice of an emergency notice to all TOs and QSEs and shall post the message electronically to the MIS Secure Area.

(3) When an emergency notice is issued, ERCOT is operating in an emergency operating condition. QSEs shall notify appropriate resources, REPs and LSEs. TOs shall notify their represented TSPs and LSEs.

4.3 Operation to Maintain Transmission System Security

(1) ERCOT Operators are responsible for operating the ERCOT System within “First Contingency” (N-1) transfer limits so that there is no overload of any significant Transmission Element whose loss could jeopardize the reliability of the ERCOT System. Whenever the ERCOT System is not engaged in emergency operation, it will be operated in such a manner that the occurrence of a Credible Single Contingency will not cause any of the following:

(a) Uncontrolled breakup of the transmission system;

(b) Loading of Transmission Facilities above defined Emergency Ratings which can not be eliminated in time to prevent damage or failure following the loss through execution of specific, predefined operating procedures;

(c) Transmission voltage levels outside system design limits which can not be corrected through execution of specific, predefined operating procedures before voltage instability or collapse occurs; or

(d) Customer Outages, except for high set interruptible and radially served loads.

(2) Significant Transmission Overload – ERCOT can:

(a) Order adjustment to unit generation schedules, switching of Transmission Elements or Load interruption to relieve a severely 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 "First Contingency" (N-1) Criteria – ERCOT can order changes to unit dispatch or commitment to eliminate a "First Contingency" (N-1) criteria violation. Normally these changes should be performed via the market control mechanisms of constraint management as described in the ERCOT Protocols, but ERCOT Operators have the authority to issue Verbal Dispatch Instructions (VDIs) independent of these systems.

(4) Violation of Voltage/Reactive Criteria – ERCOT can order changes in unit dispatch if coordinated voltage and Reactive Power criteria that are considered critical to interconnection reliability are violated for the existing or "Contingency" (N-1) conditions.

(5) Total or Partial System Blackout – ERCOT shall implement Black Start procedure.

4.3.1 Remedial Action Plans (RAP)

(1) Generation facilities or constrained Transmission Elements that would otherwise be subject to restrictions can operate to full rating if appropriate Special Protection Systems (SPS) or Remedial Action Plans (RAPs) are in place. See Section 6.2.2, Design and Operating Requirements for ERCOT System Facilities, for SPS requirements. A RAP refers to predetermined operator actions to maintain reliability in a defined adverse operating condition. 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) A RAP may be proposed by any ERCOT Market Participant, but must be approved by ERCOT prior to implementation. RAPs must meet the following requirements:

(a) Be coordinated and approved with the operators of facilities included in the RAP;

(b) Limit use to the time required to construct replacement Transmission Facilities; however, the RAP will remain in effect if replacement Transmission Facilities have been determined by ERCOT to be impractical;

(c) Comply with all applicable ERCOT and North American Electric Reliability Corporation (NERC) requirements;

(d) Clearly define and document operator actions;

(e) Include the option for the transmission operator to override the procedures if the RAP will not improve system reliability;

(f) Operators must be trained in RAP implementation; and

(g) Be defined in the Network Operations Model and considered in the Security-Constrained Economic Dispatch (SCED) and Reliability Unit Commitment (RUC). RAPs that cannot be modeled using ERCOT's existing infrastructure shall be refused or a plan developed to work around the infrastructure problem with explicit approval by the Technical Advisory Committee (TAC).

4.4 Block Load Transfers between ERCOT and Non-ERCOT System

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 or complete system shutdown. 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.

(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.

(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 Responsive Reserve (RRS) services and other 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; and

(h) Restoration of service to all Customers following major system disturbances, giving priority to the larger group of Customers.

4.5.3 Implementation

(1) ERCOT shall be responsible for monitoring system conditions, initiating the EEA levels below, notifying all Qualified Scheduling Entities (QSEs) 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 Level 3 of the EEA any time the steady-state system frequency is below 59.8 Hz and shall immediately implement Level 3 any time the steady-state frequency is below 59.5 Hz.

(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.

(7) During EEA Level 3, ERCOT must be capable of shedding sufficient firm Load to arrest frequency decay and to prevent generator tripping. The amount of firm Load to be shed may vary depending on ERCOT grid conditions during the event. Each TSP will be capable of 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 by the dispatch of personnel to substations. Since the need for firm Load shed is immediate, interruption by SCADA is preferred. The following requirements apply for an ERCOT instruction to shed firm Load:

(a) Load interrupted by SCADA will be shed without delay and in a time period not to exceed 30 minutes;

(b) Load interrupted by dispatch of personnel to substations to manually shed Load will be implemented within a time period not to exceed one hour;

(c) The initial clock on the firm Load shed shall apply only to Load shed amounts up to 1000 MW total. Load shed amount requests exceeding 1000 MW on the initial clock may take longer to implement; and

(d) If, after the first Load shed instruction, ERCOT determines that an additional amount of firm Load should be shed, another clock will begin anew. The time frames mentioned above will apply.

(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.

4.5.3.1 General Procedures Prior to EEA Operations

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:

(1) 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 levels on other Resources;

(2) Commit 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;

(3) Start Reliability Must-Run (RMR) Units available in the time frame of the emergency. RMR Units should be loaded to full capability;

(4) Issue Dispatch Instructions to QSEs to suspend any ongoing ERCOT-required generating unit testing or Resource performance testing;

(5) Utilize available resources providing Non-Spinning Reserve (Non-Spin) services as required; and

(6) ERCOT shall use the Physical Responsive Capability (PRC) to determine the appropriate emergency Notification and EEA levels.

4.5.3.2 General Procedures During EEA Operations

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.

(1) ERCOT shall suspend Ancillary Service obligations that it deems to be contrary to reliability needs;

(2) ERCOT shall notify each QSE and TO via Hotline of declared EEA level;

(3) QSEs and TOs shall notify each represented Market Participant of declared EEA level;

(4) ERCOT, QSEs and TSPs shall continue to respect confidential market sensitive data;

(5) QSEs shall update Resource plans to limit or remove capacity when unexpected start-up delays occur or when ramp limitations are encountered;

(6) QSEs shall report when On-Line or available capacity is at risk due to adverse circumstances;

(7) 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; and

(8) ERCOT shall define procedures for determining the proper redistribution of reserves during EEA operations.

4.5.3.3 EEA Levels

(1) **EEA Level 1 – Maintain a sum total of 2,300 MW that results from adding the amount of ERCOT Physical Responsive Capability (PRC) MW (Protocol Section 6.5.7.5, Ancillary Services Capacity Monitor) and the amount of RRS MW which is supplied from Load Resources.**

(a) ERCOT will:

(i) Notify the Southwest Power Pool (SPP) Reliability Coordinator;

(ii) Initiate manual HRUC Dispatch Instructions to Generation Resources available and off-line that can perform within the expected timeframe of the emergency; and;

(iii) Use available DC Tie import capacity that is not already being used and inquire about availability of BLTs.

(b) QSEs will notify ERCOT of any Resources uncommitted but available in the timeframe of the emergency.

(2) **Level 2A – Maintain a sum total of 1,750 MW that results from adding the amount of ERCOT Physical Responsive Capability (PRC) MW (Protocol Section 6.5.7.5) and the amount of RRS MW which is supplied from Load Resources.**

(a) In addition to measures associate with Level 1, ERCOT:

(i) Will instruct TSPs and Distribution Service Providers (DSPs) to reduce Customers' Load by using distribution voltage reduction measures, if deemed beneficial by the TSP or DSP;

(ii) Will instruct QSEs to deploy all Responsive Reserve (RRS) that is supplied from Load Resources (controlled by high-set under-frequency relays) in accordance with the following:

(A) Instruct QSEs to deploy half of the Responsive Reserve that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt Group 1 Load Resources providing Responsive Reserve. QSEs shall deploy Load Resources according to the group designation and will be given some discretion to deploy additional Load Resources from Group 2 if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline Verbal Dispatch Instruction (VDI), which shall initiate the ten-minute deployment period;

(B) At the discretion of the ERCOT Operator, instruct QSEs to deploy the remaining Responsive Reserve that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt Group 2 Load Resources providing Responsive Reserve. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

(C) The ERCOT Operator may deploy both of the groups of Load Resources providing Responsive Reserves at the same time. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period; and

(D) ERCOT shall post a list of Load Resources on the Market Information System (MIS) Certified Area immediately following the Day-Ahead Reliability Unit Commitment (DRUC) for each QSE with a Load Resource obligation which may be deployed to interrupt under paragraph (A), Group 1 and paragraph (B), Group 2. ERCOT shall develop a process for determining which individual Load Resource to place in Group 1 and which to place in Group 2. ERCOT procedures shall select Group 1 and Group 2 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 2A; and

(iii) With approval of the affected non-ERCOT Control Area, may instruct TSPs or DSPs to implement BLTs, which transfer Load from the ERCOT Control Area to non-ERCOT Control Areas. Use of BLT will be defined in the ERCOT Operating Guides.

(b) Confidentiality requirements regarding transmission operations and system capacity information will be lifted, as needed to restore reliability.

(3) **Level 2B – Maintain System frequency at 60 Hz. Following deployment of the measures associated with EEA Levels 1 and 2A, ERCOT will deploy available contracted EILS Loads, via a single VDI to the all-QSE Hotline; as follows:**

(a) If less than 500 MW of EILS is available for deployment, ERCOT shall deploy all Emergency Interruptible Load Service (EILS) Loads as a single block.

(b) If the amount of EILS available for deployment equals or exceeds 500 MW, ERCOT may deploy EILS Loads as a single block or may deploy EILS Loads sequentially in two groups of approximately equal size as designated by ERCOT. For a sequential group deployment, ERCOT shall instruct QSEs to deploy Group 1 immediately and to deploy Group 2 at a specified time in the future. ERCOT shall develop a random selection methodology for determining which individual EILS Loads to place in Group 1 and which to place in Group 2, and shall describe the methodology in a document posted to the MIS Public Area. Prior to an EILS Contract Period ERCOT shall notify QSEs representing EILS Loads of their EILS Loads' Group assignments.

(c) QSEs shall instruct the EILS Loads to curtail Load consistent with their commitments.

(d) EILS may be deployed at any time in a Settlement Interval.

(e) Once ERCOT has deployed EILS, EILS Loads shall remain reduced until ERCOT specifically releases the EILS deployment via a VDI to the all-QSE Hotline.

(f) Unless scheduled to go Off-Line, due either to an EILS Time Period transition or a previously scheduled period of unavailability, an EILS Load deployed for EILS shall return to its committed operating level as soon as practical following an ERCOT recall. All EILS Load shall return to normal within ten hours of being recalled.

(g) Unless a media appeal is already in effect, ERCOT shall issue an appeal through the public news media for voluntary energy conservation.

(4) **EEA Level 3 - Maintain System frequency at 59.8 Hz or greater**

(a) In addition to measures associated with EEA Levels 1, 2A, and 2B, ERCOT shall direct all TSPs and DSPs or their agents to shed firm load, in 100 MW blocks, distributed as documented in these ERCOT Operating Guides in order to maintain a steady state system frequency of 59.8 Hz.

(b) In addition to measures under EEA Levels 1 2A, and 2B, TSPs and DSPs will keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TSPs and DSPs shall not manually drop load connected to under-frequency relays during the implementation of the EEA;

4.5.3.4 Load Shed Obligation

Obligation for Load shed is by Distribution Service Provider (DSP). Load shedding obligations need to be represented by an Entity with 24x7 operations and hotline communications with ERCOT and control over breakers. (Use TOs as list of Entities).

ERCOT Load Shed Table

Transmission Operator	2009 Total Transmission

	Operator Load (MW)
American Electric Power	9.33
Austin Energy	3.96
Brazos Electric Power Cooperative	4.62
CenterPoint Energy	26.56
City of Bryan	0.57
City of College Station	0.29
City of Denton	0.49
City of Garland	0.74
CPS Energy	7.34
Greenville Electric Utility Service	0.17
Lower Colorado River Authority	5.21
Magic Valley Electric Cooperative	0.65
Oncor	35.55
Public Utility Board of Brownsville	0.43
Rayburn Country Electric Cooperative	0.93
South Texas Electric Coop-Medina Electric Coop	0.67
Texas New Mexico Power	2.35
Tex-La	0.14
ERCOT Total	**100.00**

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 termination; 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 or complete collapse of the ERCOT System. Timely implementation of a restoration plan compiled according to these Operating Guides should facilitate coordination between ERCOT, Qualified Scheduling Entities (QSEs), Resource Entities, and Transmission Operators (TOs) and ensure restoration of service to the ERCOT System at the earliest possible time. Those QSEs representing contracted Black Start Resources will provide ERCOT with 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) ERCOT shall establish and maintain a system Black Start capability plan that shall be coordinated, as appropriate, with the Black Start capability plans of neighboring regions. Documentation of system Black Start capability plans shall be provided to the North American Electric Reliability Corporation (NERC) on request.

(3) 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.

(4) 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 or complete system collapse.

(5) 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 are lifted to enable the sharing of that information that pertains to reliability including status information and recovery activities.

4.6.2 Strategies

In the event of a partial or complete system blackout, 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.

(1) 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.

(2) Each QSE with representing Black Start Resources should initiate communications with its Black Start Resources and immediately notify ERCOT and the appropriate TO of their condition and status.

(3) Available Black Start Resources should immediately start their isolation and startup procedures and attempt to establish communications with the local TO.

(4) As generating and transmission capabilities become available, systematic restoration of ERCOT Load with respect to priorities should begin in accordance with the local TO Black Start plans, taking care to balance Load and generating capability while maintaining an acceptable frequency.

(5) 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

Priorities for an ERCOT System Black Start recovery are listed below:

(1) Secure and/or stabilize generating units where necessary.

(2) Prepare transmission corridors as necessary to support restoration.

(3) Assess ERCOT System condition, and available communication facilities.

(4) Restore and maintain communication facilities to the extent possible.

(5) Bring units with contracted Black Start capability On-Line.

(6) Provide service to critical facilities:

    (a) Provide station service for nuclear generating facilities;

    (b) Provide critical power to as many power plants as possible to prevent equipment damage;

(c) Secure or provide startup power for generating plants that do not have Black Start capability; and

(d) Supply station service to critical substations where necessary.

(7) Connect islands at designated synchronization points taking care to avoid recurrence of a partial or complete system collapse.

(8) Restore service to critical Loads such as:

(a) Military facilities;

(b) Facilities necessary to restore the electric utility system, including fuel sources;

(c) Law enforcement organizations and facilities affecting public health; and

(d) Public communication facilities.

(9) 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 NERC Reliability Standards;

(b) Coordinate and approve Planned Outage schedule for contracted Black Start Generation Resources;

(c) Train QSE, TO, Resource Entity, and Market Participant personnel in the implementation and use of the Black Start plan;

(d) Will review the plans and procedures for consistency and conformance with these Operating Guides and ensure that they are updated at least annually;

(e) Will make annual reports during the first quarter to the Reliability and Operations Subcommittee (ROS) of plan review and any testing activities of Black Start Generation Resources;

(f) Shall verify that the number, size, and location of system Black Start Generation Resources are sufficient to meet system restoration plan expectations; and

(g) In the event of an ERCOT System collapse, ERCOT will:

(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, TOs, Resource Entities, and Market Participants;

(v) Direct the distribution of reserve;

(vi) Coordinate the return of the ERCOT System to AGC.

(2) TOs' responsibilities are as follows:

(a) Shall maintain a local Black Start plan which coordinates with the ERCOT Black Start Plan; and

(b) In event of an ERCOT or wide area blackout:

(i) Shall communicate with local Black Start units and the Black Start unit's QSE;

(ii) Coordinate switching to next start units and local Load;

(iii) Shall implement its local Black Start plan;

(iv) Shall follow the direction of ERCOT on behalf of represented TSPs and DSPs;

(v) Shall act as the regional ERCOT representative in coordinating interconnection of units; and

(vi) Shall follow the direction of ERCOT for reconnection of islands.

(3) QSEs', Resource Entities', and Market Participants' responsibilities are as follows:

(a) Shall use the ERCOT and local TO Black Start plan;

(b) Verify that associated personnel are proficient in its implementation and use; and

(c) In the event of an ERCOT System collapse, the QSEs, Resource Entities, and Market Participants will:

(i) Take immediate steps to initiate the local Black Start plan;

(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 picking up local Load and starting next units; and

(iv) Provide available assistance as directed by ERCOT or the local TO.

(4) Section 8, Attachment A, Detailed Black Start Information, provides 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.

ERCOT Nodal Operating Guides

Section 5: Planning

November 1, 2007

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

*** All References to Protocols and Operating Guides throughout this document are to Nodal Protocols and Nodal Operating Guides*

5 Planning

5.1 Planning Criteria

5.1.1 Introduction

(1) The ERCOT System consists of those generation and Transmission Facilities (60 kV and higher voltages) that are controlled by individual Market Participants (MPs) and that function as part of an integrated and coordinated power supply network. Each reference in this document to MPs includes Generation Resources. Qualified Scheduling Entities (QSEs), Competitive Retailers (CRs), Transmission Service Providers (TSPs), Distribution Service Providers (DSPs) and others that use the ERCOT Transmission Grid.

(2) To maintain reliable operation of the ERCOT System, it is necessary that all MPs observe and subscribe to certain minimum planning criteria. The criteria set forth herein, combined with the applicable North American Electric Reliability Corporation (NERC) Reliability Standards constitute the aforementioned minimum planning criteria. Tests outlined herein shall be performed to determine conformance to these minimum criteria; however, ERCOT recognizes that events more severe than those outlined in these criteria could cause grid separation, other tests may also be performed, if necessary, for information purposes.

(3) The complexity and uncertainty inherent in the planning and operation of the ERCOT System make exhaustive studies impracticable; therefore, to gain maximum benefit from the limited number of tests performed, the selection of the specific tests and the frequency of their performance will be made solely upon the basis of the expected value of the reliability information obtainable from the test.

(4) It is the responsibility of each Transmission Service Provider (TSP) to perform tests appropriate to ensure the reliability of its Transmission Facilities. Further the TSP may recommend additional studies by ERCOT or the Reliability Operations Subcommittee (ROS). Additional tests which may affect multiple TSPs or the ERCOT System as a whole may be studied. Upon consideration of such recommendations, ERCOT and the ROS shall coordinate the performance of such studies, as necessary, to assess the reliability of the planned ERCOT System.

(5) ERCOT Regional Planning Groups or ERCOT System Planning shall determine and demonstrate the need for any static and/or dynamic Reactive Power capability in excess of the explicit requirements of the ERCOT Protocols and Operating Guides that is necessary to ensure compliance with the ERCOT Planning Criteria. ERCOT Transmission Planning shall establish specific TSP responsibility for any associated facility additions.

(6) ERCOT, in cooperation with the TRE, will review the ERCOT Planning Criteria every three years to ensure it meets the requirements in the NERC Reliability Standards. ERCOT, in cooperation with the TRE, will periodically review the planning criteria, procedures, and practices of individual ERCOT TSPs to ensure consistency with all applicable NERC Reliability Standards and the ERCOT Planning Criteria.

5.1.2 Real-Time and Short Term Planning

ERCOT will conduct Real-Time and short term planning based on the security criteria established in the ERCOT Protocols and these Operating Guides. Operations during Forced and Planned Outages will also follow these criteria. Line ratings are provided to ERCOT in accordance with ERCOT Protocols and these Operating Guides. ERCOT will employ congestion management, Special Protection Systems (SPS), Remedial Action Plans (RAPs) and transmission switching schemes to facilitate the market use of the ERCOT Transmission Grid while maintaining system security and reliability in accordance with ERCOT and 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 ERCOT Protocols and these Operating Guides.

5.1.3 Load Forecasts

(1) Each DSP or its Designated Agent directly interconnected with the ERCOT Transmission Grid shall provide annual Load forecasts to ERCOT as outlined in the ERCOT Annual Load Data Request (ALDR) Procedures.

(2) For each substation not owned by either a TSP or a DSP, the owner shall provide a substation Load forecast to the directly-connected TSP sufficient to allow it to adequately include that substation in its ALDR response.

(3) If load data is not timely submitted on the schedule and in the format defined by the TSP, then ERCOT shall calculate loads based on historical data and insert these loads into the load flow cases during DataSet A and DataSet B annual updates.

5.2 Resource Capability

(1) ERCOT will periodically determine the minimum reserve margin required to ensure the adequacy of installed generation and other resource capability in ERCOT. ERCOT or the Public Utility Commission of Texas (PUCT) may also approve specific Market Participant (MP) requirements to ensure that the required minimum reserve margin is maintained.

(2) ERCOT maintains a database containing existing and proposed generation or other resource capability historical and projected values for demand and energy and proposed major transmission grid additions. This database is updated periodically and the Capacity Demand Reserve (CDR) Working Paper is produced annually by ERCOT.

5.3 Transmission Reliability Studies

(1) The interconnection philosophy of ERCOT is to minimize loss of Load by remaining interconnected. Interconnected system planning will include steady state and dynamic simulated testing by ERCOT and Transmission Service Providers (TSPs) to represent specific occurrences for each type of contingency specified below or listed in Table 5-1, Transmission Systems Standards — Normal and Contingency Conditions, in Section 5.5.1, System Assessments, and the NERC Reliability Standards. The term “generating unit”,

as used in Table 5-1, for the purpose of reliability studies shall be defined as the largest single generating unit operating at a given voltage level at each plant location. In the case of a Combined Cycle Facility, the term "generating unit", as used in Table 5-1, shall be considered as the total generating capacity of the entire train as defined in Section 1, Overview. Also included in Table 5-1 are "ERCOT Clarifications and Definitions" that are applicable to studies for NERC Reliability Standards Categories C and D.

(2) The contingency studies will be performed for reasonable variations of Load level, generation schedules, planned transmission line Maintenance Outages, and anticipated power transfers. At a minimum, this should include projected Loads for the upcoming summer and winter seasons and a five-year planning horizon. The TSPs involved should plan to resolve any unacceptable study results through the provision of Transmission Facilities, the temporary alteration of operating procedures (i.e., RAPs), temporary Special Protection Systems (SPSs), or other means as appropriate.

(3) While the requirements listed in Table 5-1 address most ERCOT planning concerns, studies will also be conducted to ensure that Credible Single Contingencies (see Section 1.4, Definitions) do not result in the following:

(a) Cascading or uncontrolled outages;

(b) Instability of generating units at multiple plant locations; or

(c) Interruption of service to firm demand or generation other than that isolated by the double-circuit loss, following the execution of all automatic operating actions such as relaying and special protection systems. Furthermore, the loss should result in no damage to or failure of equipment and, following the execution of specific non-automatic predefined operator-directed actions (i.e., RAPs), such as generation schedule changes or curtailment of interruptible Load, should not result in applicable voltage or thermal ratings being exceeded.

(4) Voltage stability margin shall be sufficient to maintain post-transient voltage stability under the following study conditions:

(a) For each ERCOT defined area, a 5% increase in Load above expected peak supplied from resources external to the ERCOT defined area; and NERC Category A or B operating conditions (see Table 5-1 in Section 5.5.1, System Assessments);

(b) For each ERCOT defined area, a 2.5% increase in Load above expected peak supplied from resources external to the ERCOT defined area; and NERC Category C operating conditions (see Table 5-1 in Section 5.5.1, System Assessments).

(5) ERCOT is responsible for gathering Load data for use in the ERCOT Load flow cases via the ALDR. The Reliability and Operations Subcommittee (ROS) coordinates with ERCOT in the performance of steady state and dynamic simulation studies of the bulk

electric system to determine the impact on the planned system of occurrences of the types of contingencies listed in the NERC Reliability Standards. The Steady State Working Group (SSWG), Dynamics Working Group (DWG) and System Protection Working Group (SPWG) shall coordinate with ERCOT to create databases and perform tests as outlined in these criteria.

(6) These databases created by the ROS working groups are available for use by MPs. The individual TSPs affected by identified issues will pursue appropriate solutions. It is the responsibility of the individual TSPs to use these databases to:

(a) Perform steady state and dynamic tests appropriate to evaluate the compliance of their Transmission Facilities within the ERCOT Planning Criteria; and

(b) Recommend other tests which examine effects of importance to multiple TSPs.

(7) Other System Planning requirements and expectations are outlined in ERCOT's System Planning Charter.

5.4 Reports of Studies

ERCOT annually directs the preparation of Department of Energy (DOE) reports. These reports address the adequacy of the ERCOT System and provide input to various North American Electric Reliability Corporation (NERC) reports. The adequacy of the planned ERCOT System is based on studies performed by ERCOT and individual Transmission Service Providers (TSPs).

5.5 System Modeling Information

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 (MPs) are required:

(1) Each TSP, or its Designated Agent, shall provide accurate modeling information for all ERCOT Transmission Facilities owned or planned by the Transmission Service Provider (TSP). The information provided shall include, but not be limited to, the following:

(a) 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);

(b) 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

(c) 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 - Normal and Emergency - 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. ..

(2) Any long-term changes to the reactive capability must be provided by the facility owner to ERCOT, as planned at least 30 days prior to implementation and as built no later than 30 days after implementation, as changes or upgrades are made during the life of the Reactive Power facilities.

(3) Further, each TSP owning or planning Transmission Facilities or its Designated Agent 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.

(4) Each Generation Resource, or its Designated Agent, shall provide accurate modeling information for each existing or publicly-announced ERCOT generating unit for which it is the majority owner. The information provided shall include, but not be limited to, the following:

(a) Information necessary to represent the Generation 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

(b) Identification of a designated contact person responsible for providing answers to questions ERCOT may have regarding the information provided.

(5) Typical or representative information may be provided for planned facility additions or modifications, but such information shall be revised using actual design or construction information no later than 90 days after the facility has been energized or otherwise placed into service.

(6) Congestion Revenue Rights (CRR) Network Model Outage determination uses network topology of the CRR Network Model identified by ERCOT Staff. This must include Planned Outages of Transmission Elements approved 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 Staff 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:

(a) Consecutive or continuous approved Outages greater than or equal to five days;

(b) Approved Outages which include Transmission Elements included in the definition of a Hub;

(c) Approved Outages which include Transmission Elements in a 345 kV Transmission Facility;

(d) Approved Outages that require the use of a Block Load Transfer (BLT); and

(e) Any other approved Outage that has been determined by ERCOT Staff to carry a substantial risk of causing significant congestion.

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 in Protocol Section 7.5.1, Nature and Timing.

5.5.1 System Assessments

ERCOT and TSPs or their Designated Agent shall conduct reliability assessments as required by the NERC Reliability Standards and Public Utility Commission of Texas (PUCT) Substantive Rules. MPs shall supply all relevant data required to assist in the preparation of these assessments as requested by ERCOT. This is in addition to data required by the ERCOT Protocols, ERCOT System Planning Charter or these Operating Guides.

Table 5-1: Transmission Systems Standards — Normal and Contingency Conditions				
Category	**Contingencies**	**System Limits or Impacts**		
	Initiating Event(s) and Contingency Element(s)	**System Stable and both Thermal and Voltage Limits within Applicable Ratings[a]**	**Loss of Demand or Curtailed Firm Transfers**	**Cascading Outages**
A: No Contingencies	All Facilities in Service	Yes	No	No
B: Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C: Event(s) resulting in the loss of two or more	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal	Yes Yes	Planned/Controlled[c] Planned/Controlled[c]	No No

Table 5-1: Transmission Systems Standards — Normal and Contingency Conditions				
Category	**Contingencies**	**System Limits or Impacts**		
	Initiating Event(s) and Contingency Element(s)	**System Stable and both Thermal and Voltage Limits within Applicable Ratings[a]**	**Loss of Demand or Curtailed Firm Transfers**	**Cascading Outages**
(multiple) elements.	fault)			
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/Controlled[c] Planned/Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transmission Circuit 8. Transformer 9. Bus Section	Yes Yes Yes Yes	Planned/Controlled[c] Planned/Controlled[c] Planned/Controlled[c] Planned/Controlled[c]	No No No No
D [d]: Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers)	Evaluate for risks and consequences. • May involve substantial loss of customer Demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems		

Table 5-1: Transmission Systems Standards — Normal and Contingency Conditions				
Category	**Contingencies**	**System Limits or Impacts**		
	Initiating Event(s) and Contingency Element(s)	**System Stable and both Thermal and Voltage Limits within Applicable Ratings[a]**	**Loss of Demand or Curtailed Firm Transfers**	**Cascading Outages**
	10. Loss of a all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization.			

Footnotes to Table 5-1:

(a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

(b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

(c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

(d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

(e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

(f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossing) in accordance with Regional exemption criteria.

5.5.2 ERCOT Clarifications and Definitions of NERC Reliability Standards Contingency Categories C and D

5.5.2.1 Category C

(1) Bus Section Definition - "Bus Section" shall be interpreted to mean any section of buswork, which would be isolated by normal relay/breaker operation when faulted.

(2) Manual System Adjustments Definition - "Manual System Adjustments" shall be interpreted to include only operator actions that:

(a) Would be made no later than one hour after clearing of the first fault;

(b) Are made using remote control capability or communications with other operators having such capability;

(c) Include circuit switching, changes in the schedules of generating units operating at clearing of the first fault, and changes in the schedules of other generating units that can contribute within one hour; and

(d) Exclude the physical repair or replacement of damaged equipment and the starting of any generating unit that cannot contribute within one hour.

(3) Planned Loss of Demand or Curtailed Firm Transfer Definition - All Load interruption, generator tripping, or generation schedule changes must be either automatic or prearranged with associated written operating procedures. Actions must be executable in time to avoid any equipment damage or safety violations, but in any case within 30 minutes of fault clearing.

(4) Cascading Outage Definition - Cascading Outages are defined as the uncontrolled loss of any system facilities or load, whether because of thermal overload, voltage collapse, or loss of synchronism, except those occurring as a result of fault isolation.

(5) Implementation Guidelines - Evaluation of all the possible combination of facility Outages under Category C is not required. Each TSP with bulk Transmission Facilities will evaluate one or more Category C contingencies annually. The contingencies selected may be based on the results of related studies or actual events. In either case, the selected contingencies must indicate more severe results or impacts based on the engineering judgment of the facility owner, ERCOT or any TSP. An explanation of why any remaining contingencies would produce less severe system results shall be available as supporting information.

5.5.2.2 Category D

(1) For the purpose of evaluating the consequences resulting from a Category D event, a Large Load or Major Load Center is an electrical demand of between 50 and 500 MW. This may be a large single Load or a group of electrically close Loads. The loss of this demand will not include any other system elements other than those directly connected.

(2) Evaluations of Category D contingencies are not required to be performed annually. Evaluations should be performed for the following:

(a) Contingencies previously studied for which the conditions assumed in the study have changed significantly and which may adversely affect the results of the study; and

(b) Contingencies not previously studied that, based on the results of related studies or actual events may in the engineering judgment of the facility owner, ERCOT or any TSP, have unacceptable consequences.

ERCOT Nodal Operating Guides

Section 6: Disturbance Monitoring and System Protection

August 1, 2010

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

---

6 Disturbance Monitoring and System Protection

6.1 Disturbance Monitoring Requirements

6.1.1 Introduction

(1) Disturbance monitoring is necessary to determine:

(a) The performance of the ERCOT System;

(b) The effectiveness of protective relaying systems;

(c) Verify ERCOT System models; and

(d) The causes of ERCOT System disturbances (unwanted trips, faults, and protective relay system actions).

(2) To ensure that adequate data is available for these activities, the disturbance monitoring requirements and procedures discussed in this document have been established by ERCOT for facility owners in the ERCOT System.

(3) Disturbance monitoring equipment includes digital fault recorders, certain protective relays with fault recording capability, and dynamic disturbance recorders. Sequence-of-event recorders, although considered equipment to monitor disturbances, are not preferred devices, as they provide limited information. Sequence-of-event recorders have been replaced by digital fault recorders and microprocessor-based protective relays.

6.1.2 Fault Recording Equipment

Fault recording equipment includes digital fault recorders and protective relays with fault recording capability that meet the triggering requirements below. Fault recording equipment required by these Operating Guides shall be time synchronized with a Global Positioning System-based clock, or ERCOT-approved alternative, with sub-cycle (17 milli-second) timing accuracy and performance.

6.1.2.1 Triggering Requirements

Fault recording equipment triggering must occur for system voltage magnitude and current magnitude disturbances (delta V and delta I) without requiring any circuit breaker operations or trip outputs from protective relay systems. Triggering shall be adjusted to operate for faults in the area to be monitored, which should overlap into the area of coverage of adjacent fault recorders.

6.1.2.2 Location Requirements

(1) The location criteria below shall apply to equipment operated at or above 100 kV. The facility owner, whether registered as a Transmission Service Provider (TSP) or Resource Entity, shall install fault recording equipment at the following facilities, at a minimum:

(a) Interconnections to other regions (i.e. outside ERCOT Region);

(b) Substations where electrical transfers of equipment can be made between the ERCOT Region and another region;

(c) Substations having three or more non-radial 345 kV line terminals. If a switching station is one bus removed from a station with a larger number of line terminals, then the fault recorder shall be located at the larger station and not required at the smaller station;

(d) Substations that are more than one circuit breaker-controlled bus away from a fault recorder and have five or more non-radial line terminals;

(e) For the purpose of evaluating items (c) and (d) above, autotransformer or generating capacity totaling 150 MVA or greater, based upon minimum nameplate rating upon which transformer impedance is stated, i.e., base rating, shall constitute a non-radial line terminal at the highest voltage level to which it is directly connected; and

(f) All generating station switchyards connected to the ERCOT System with an aggregated generating capacity above 100 MVA or the remote line terminals of each generating station switchyard;

(2) All fault recording equipment shall be either digital fault recorders or fault recording protective relays.

6.1.2.3 Data Recording Requirements

(1) The following quantities must be recorded for equipment operating at 100 kV or above at facilities where fault recording equipment is required:

(a) Two sets of voltages for breaker-and-a-half and ring bus substation configurations. One set of voltages for each bus in other substation configurations. A set of voltages shall consist of each phase voltage waveform and the residual voltage waveform;

(b) For all lines, neutral (residual) current waveform;

(c) Circuit breaker status;

(d) Circuit breaker trip circuit status; and

(e) Date and time stamp (CST).

(2) For all new or upgraded fault recorder installations, additional items must also be recorded, as follows:

(a) For all autotransformers, current waveform for three phases and either neutral / residual current waveform or current waveform in delta windings;

(b) For all lines, two phase current waveforms;

(c) Status – carrier transmitter control, i.e. start, stop, keying; and

(d) Status – carrier received.

6.1.2.4 Data Retention and Reporting Requirements

(1) The facility owner shall store all recorded fault data for at least a two year period. This data shall be stored in the form of a computer file or files.

(2) Facility owners shall provide fault recordings to ERCOT or North American Electric Reliability Corporation (NERC) upon their request, within five days, along with channel identification and scaling information to allow analysis of the recordings. Fault recordings shall be shared between facility owners, upon their request, for the analysis of system disturbances.

(3) When multiple recordings exist for a single event, only report to ERCOT and NERC of data from the best recording, usually the closest recorder, is required.

(4) Data submissions shall be COMTRADE fault recordings, .cfg and .dat files, and one or more identification files that associate the COMTRADE recordings with system disturbances and ERCOT short circuit database bus numbers. The identification file shall be a Microsoft Excel© spreadsheet or comma delimited ASCII text that can be read into a Microsoft Excel© spreadsheet. For this file, the data fields to be reported for each record, in the following order, are:

REPORTING ENTITY

Faulted Circuit	**Circuit or Bus (1, 2, A, B, N, S, etc.)**
	From Bus (ERCOT short circuit database bus number)
	To Bus (ERCOT short circuit database bus number)
	Nominal Voltage of Faulted Branch or Bus (kV)
Physical Fault Location in Percent from “From Bus” (if physical location found, i.e. not calculated location. If physical location not found, leave blank)	
	Date (CST, MM/DD/YYYY)
	Time (CST, HH:MM:SS, 24 hour format)
	Cause Code

Fault Recorder Data	**Circuit (1, 2, A, B, N, S, etc.)**
	From Bus – Monitored branch (ERCOT short circuit database bus number)
	To Bus – Monitored branch (ERCOT short circuit database bus number)
	Nominal Voltage of Monitored Branch (kV)
	Measured Current Magnitude (primary value in RMS amperes)
	Recorded Fault Duration (cycles)
	Fault Type (using reporting entity's phase designations – AB, CG, etc.)
Optional Comments (40 char. max.)	

(5) ERCOT shall compile a summary list of all available 345 kV fault recordings annually based on each facility owner's submitted data. This summary shall contain for each recording the date, time, fault recorder owner, fault recorder location, the primary system element recorded, and an optional use comment field. This summary shall be available to any ERCOT Member upon their request. Record summaries will be retained by ERCOT for a minimum of three years.

6.1.2.5 Maintenance and Testing Requirements

Facility owners shall maintain and test their fault recording equipment as follows:

(1) In accordance with the manufacturer's recommendations;

(2) Calibration of the analog (waveform) channels shall be performed at installation and when records from the equipment indicate a calibration problem. Calibration can be monitored through the analysis and correlation of fault records with system models and the records of other fault recorders in the area; and

(3) Fault recording equipment must be operationally tested at least annually to ensure that the equipment is functional. Acceptable tests are the production of a manually triggered record either remotely or at the device, or automatic record production due to a power system disturbance.

6.1.3 Dynamic Disturbance Recording Equipment

RESERVED

6.1.4 Equipment Reporting Requirements

(1) Facility owners shall maintain a current database summarizing their disturbance monitoring equipment installations.

(2) The database shall include installation location, type of equipment, make and model of equipment, operational status, a listing of the major equipment being monitored and the date the equipment was last tested. This database shall be submitted to ERCOT annually, by October 30. Additionally, a complete list of all monitored points at each installation shall be maintained by Facility owners and provided, when requested specifically by ERCOT or NERC, within 30 days.

(3) ERCOT shall maintain a comprehensive database of all facility owner's disturbance monitor equipment submittals, updated annually.

6.1.5 Review Process

ERCOT shall review fault recorder and disturbance recorder locations for compliance and adequacy when significant changes are made to the ERCOT System or at least every five years.

6.2 System Protective Relaying

6.2.1 Introduction

(1) The satisfactory operation of the ERCOT System (equipment operated above 60 kV), especially under abnormal conditions, is greatly influenced by protective relay system. Protective relay systems are defined as the total combination of:

(a) The protective relays;

(b) Associated communications system;

(c) Voltage and current sensing devices; and

(d) The Direct Current Tie (DC Tie) system up to the terminals in the circuit breaker.

(2) Although relaying of tie points between facility owners is of primary concern to the ERCOT System, internal protective relay system 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 system of individual facility owners shall not adversely affect the stability of ERCOT System interconnections. Additional minimum protective relay system requirements are outlined in the North American Electric Reliability Corporation (NERC) Reliability Standards.

(3) These objectives and design practices shall apply to all new protective relay system 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 system at these locations and to make any modifications that they deem necessary. Similar assessment and judgment should be used with respect to protective relay system 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 system shall be designed to provide reliability, a combination of dependability and security, so that protective relay system will perform correctly to remove faulted equipment from the ERCOT System.

(2) For planned ERCOT System conditions, protective relay system shall be designed not to trip for stable 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 system 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 elements may be subjected, even under first-contingency conditions.

(5) Applicable Institute of Electrical and Electronic Engineers (IEEE)/American National Standards Institute (ANSI) guides shall be considered when applying the protective relay system 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) All facility owners shall give sufficient advance notice to ERCOT of any changes to their facilities that could require changes in the protective relay system of neighboring facility owners.

(8) Facility owners' operations personnel shall be familiar with the purposes and limitations of the protective relay system.

(9) The design, coordination, and maintainability of all existing protective relay systems shall be reviewed periodically by the facility owner to ensure that the protective relay systems continue to meet ERCOT System requirements. This review shall include the need for redundancy. Where redundant protective relay systems are required, separate AC current inputs and separately fused DC control voltages shall be provided with the upgraded protective relay system. 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.

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

(11) 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 the protective relay system.

(12) 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.

(13) Special Protection Systems (SPS) are protective relay systems designed to detect abnormal ERCOT System conditions and take pre-planned corrective action, other than the isolation of faulted elements, to provide acceptable ERCOT System performance. SPS actions include, but are not limited to, changes in Demand, generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings. An SPS does not include under-frequency or under-voltage Load shedding.

(a) A "Type 1 SPS" is any SPS that has wide-area impact and specifically includes any SPS that:

(i) Is designed to alter generation output or otherwise constrain generation or imports over DC Ties; or

(ii) Is designed to open 345 kV transmission lines or other lines that interconnect Transmission Service Providers (TSPs) and impact transfer limits.

(b) A "Type 2 SPS" is any SPS that has only local-area impact and involves only the facilities of the owner-TSP. The determination of whether an SPS is Type 1 or Type 2 will be made by ERCOT upon receipt of a description of the SPS from the SPS owner. Any SPS, whether Type 1 or Type 2, shall meet all requirements of the NERC Reliability Standards relating to SPSs, and shall additionally meet the following ERCOT requirements:

(i) The SPS owner shall coordinate design and implementation of the SPS with the owners and operators of facilities included in the SPS, including but not limited to Generation Resources and DC Ties;

(ii) The SPS shall be automatically armed when appropriate;

(iii) The SPS shall not operate unnecessarily. To avoid unnecessary SPS operation, the SPS owner may provide a Real-Time status indication to the owner of any Generation Resource controlled by the SPS to show when the flow on one or more of the SPS monitored facilities exceeds 90% of the flow necessary to arm the SPS. The cost necessary to provide such status indication shall be allocated as agreed by the SPS owner and the Generation Resource owner;

(iv) The status indication of any automatic or manual arming/activation or operation of the SPS shall be provided as Supervisory Control and Data Acquisition (SCADA) alarm inputs to the owners of any facility(ies) controlled by the SPS; and

(v) When a TSP removes a SPS from service, the TSP or its Designated Agent shall immediately notify ERCOT Operations. ERCOT shall modify its reliability constraints to recognize the unavailability of the SPS and notify the market via the Market Information System (MIS) Public Area. When a SPS is returned to service, the TSP or its Designated Agent shall immediately notify ERCOT Operations. ERCOT shall modify its reliability constraints to recognize the availability of the SPS.

(iv) The status indication of the following items shall be provided by SCADA telemetry provided by the owner of the SPS equipment to ERCOT for incorporation into ERCOT systems:

(A) Any automatic or manual arming/activation or operation of the SPS;

(B) The in-service/out-of-service status of the SPS; and

(C) Any additional related telemetry that already exists pertinent to the monitoring of the SPS (e.g. status indication of communications links between associated SPS equipment and TSP control center, arming limits of associated SPS equipment).

(14) The owner(s) of an existing, modified, or proposed SPS shall submit documentation of the SPS to ERCOT for review and compilation into an ERCOT SPS database. The documentation shall detail the design, operation, functional testing, and coordination of the SPS with other protection and control systems.

(a) ERCOT shall conduct a review of each proposed SPS and each proposed modification to an existing SPS. Additionally, it shall conduct a review of each existing SPS at least every five years as required by changes in system conditions. Each review shall proceed according to a process and timetable documented in ERCOT Procedures and posted on the MIS Secure Area.

(b) For a proposed Type 1 SPS, the review must be completed before the SPS is placed in service, unless ERCOT specifically determines that exemption of the proposed SPS from the review completion requirement is warranted. The timing of placing the SPS 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) For a proposed Type 2 SPS, the SPS may be placed into service before completion of the ERCOT review, with advanced prior notice to ERCOT in the form of a NOMCR. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. Existing SPSs that have already undergone at least one review shall remain in service during any subsequent review, and proposed modifications to existing SPSs may be implemented, upon notice to ERCOT, and approval of ERCOT before completion of the required ERCOT review.

(d) The process and schedule for placing an SPS into service must be consistent with documented ERCOT Procedures. The schedule must be coordinated among ERCOT and the owners of any facility(ies) controlled by the SPS, and shall provide sufficient time to perform any necessary testing prior to its being placed in service.

(e) An ERCOT SPS review shall verify that the SPS complies with the ERCOT Protocols, NERC Reliability Standards and these Operating Guides. The review shall evaluate and document the consequences of failure of a single component of the SPS, which would result in failure of the SPS to operate when required. The review shall also evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an SPS, when considered by itself, and without any other system contingency. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. The current review results shall be kept on file and supplied to NERC on request within 30 days.

(f) As part of the ERCOT review and unless judged to be unnecessary by ERCOT, the appropriate Reliability and Operations Subcommittee (ROS) working groups such as the Steady State Working Group (SSWG), the Dynamics Working Group (DWG), and/or the System Protection Working Group (SPWG) shall review the SPS and report any comments, questions, or issues to ERCOT for resolution. ERCOT may work with the owner(s) of facilities controlled by the SPS as necessary to address all issues.

(g) ERCOT shall develop a methodology to include the SPS in Security-Constrained Economic Dispatch (SCED), Outage Coordination, and Reliability Unit Commitment (RUC).

(h) ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the SPS.

(15) SPS owners shall notify ERCOT of all SPS operations. Documentation of SPS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report located in Section 8, Attachment B, Relay Misoperation Report. ERCOT shall conduct an analysis of all SPS operations, misoperations, and failures. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented.

(a) ERCOT shall report all SPS operations and misoperations to the Texas Regional Entity (TRE) for review. SPS arming or activation that ramps generation back is not considered an operation or misoperation with respect to reporting requirements to TRE. An operation and misoperation of an SPS with respect to reporting requirements to TRE occurs when changes to the transmission system occur, including, but not limited to circuit breaker operation. Owners of SPSs will provide a monthly report to ERCOT by the 15th of each month, for the previous month, describing each instance an SPS armed/activated and reset. The report will include the date and time of arming/activation and reset. ERCOT shall consolidate the monthly reports and forward to TRE.

(b) If an SPS 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 Generation Resource owner(s) to decrease the available capability on the affected Generation Resource(s). The amount of available capacity to be decreased shall be determined by ERCOT. The decreased available capacity on the Generation Resource(s) shall remain until the Generation Resource owner(s) provides documentation that demonstrates the Generation Resource(s) can properly control output in a pre-contingency or normal ERCOT System condition.

(16) For each SPS, the owner shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. This shall take place according to a timetable documented in ERCOT Procedures and posted on the MIS Secure Area. Once an exit strategy is complete and a SPS is no longer needed, the owner of an existing SPS shall notify ERCOT, using a NOMCR, whenever the SPS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all facilities controlled by the SPS.

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 promptly and any deficiencies investigated and corrected.

(2) All protective relay system misoperations in systems 100 kV and above shall be documented, including corrective actions and the documentation supplied by the affected facility owner to ERCOT or NERC upon their request within five Business Days. All protective relay system misoperations shall be documented using the form in Section 8,

Attachment B, Relay Misoperation Report. 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;

(b) Slow Trip – A correct 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 intends;

(c) Unnecessary Trip During a Fault – Any relay initiated operation of a circuit breaker during a fault when the fault is outside the intended zone of protection;

(d) Unnecessary Trip Other Than Fault – The unintentional operation of a protective relay system, which causes a circuit breaker to trip when no system fault is present. May be due to vibration, improper settings; load swing, defective relays, or SCADA system malfunction;

(e) Employee action that directly initiates a trip is not included in this category. It is the intent of this reporting process to identify misoperations of the relay system as it interrelates with the electrical system, not as it interrelates to personnel involved with the relay system. With this in mind, if an individual directly initiates an operation, it is not counted as a misoperation (i.e., unintentional operation during tests). On the other hand, 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 relay system misoperation; and

(f) Failure to Reclose – Any failure of a protective relay system to automatically reclose following a fault if that is the design intent.

(3) All SPS misoperations shall be documented, including corrective actions and the documentation supplied to ERCOT and NERC upon request within five Business Days. All SPS misoperations shall be documented using the form in Section 8, Attachment B, Relay Misoperation Report. Any of the following events constitute a reportable SPS misoperation:

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

(b) Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed;

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

(d) Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s); and

(e) Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions if that is the design intent.

(4) Facility owners shall document the performance of their protective relay system utilizing the method described in the paper "Transmission Protective Relay System Performance Measuring Methodology", IEEE/PSRC Working Group 13 September 16, 1999. Facility owners shall report the performance of their 345 kV protective relay system for the previous 12 months to ERCOT on an annual basis. The performance data reported shall include the total number of protective relay system misoperations, the total number of events, and the factor "k".

(5) At least annually, ERCOT shall review the protective relay system misoperation reports and 345 kV performance data of facility owners for analysis of protective relay system performance and compliance.

(6) All facility owners shall install, maintain, and operate disturbance monitoring equipment in accordance with the requirements in Section 6.1.2.3, Data Recording Requirements.

(7) Facility owners shall provide an assessment of the system performance results of simulation tests of the contingencies in Table I of NERC Reliability Standard TPL-001. These assessments should be based on existing protection systems and any existing backup or redundancy protection systems to determine that existing transmission protection systems are sufficient to meet the system performance levels as defined in NERC Reliability Standards and the associated Table I. All non-compliance findings shall be documented, including a plan for achieving compliance. These assessments shall be provided to NERC or ERCOT on their request within 30 days.

6.2.4 Maintenance and Testing Requirements for ERCOT System Facilities

(1) The facility owner shall test and verify the operation of each new or modified protective relay system prior to placing the equipment in its zone of protection in service.

(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.

6.2.5 Requirements and Recommendations for ERCOT System Facilities

6.2.5.1 General Protection Criteria

6.2.5.1.1 Dependability

(1) Except as noted in items (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 system 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.

6.2.5.1.2 Security

The protective relay system 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 system 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.

6.2.5.1.3 Dependability and Security

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

(2) To the maximum degree practicable, the components used in the protective relay system 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 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 system 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.

6.2.5.1.4 Operating Time

The objective of the protective relay system 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:

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

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

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

6.2.5.1.5 Testing and Maintenance

(1) The design of the protective relay system 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.

(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.

6.2.5.1.6 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.

6.2.5.2 Equipment and Design Considerations

6.2.5.2.1 Current Transformers

(1) Current transformers associated with the protective relay system 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) 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.

6.2.5.2.2 Voltage Transformers and Potential Devices

(1) Voltage transformers and potential devices associated with the protective relay system 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 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. The two protective relay systems protecting ERCOT System facilities may use separate secondary windings of the voltage transformers 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.

(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 138kV and above.

(6) Other considerations include:

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

(b) Capacitor coupled voltage transformers are suitable for relaying and SCADA (Supervisory Control And Data Acquisition) telemetry; and

(c) Report loss of voltage transformer voltage such as a voltage transformer fuse failure over SCADA.

6.2.5.2.3 Batteries and Direct Current (DC) Supply

(1) Direct Current (DC) batteries associated with the protective relay system 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 systems protecting a zone shall be supplied from the separate sources or branches. For a new facility, two batteries shall be required in locations that remote backup clearing of lines and substation faults is not achieved. Where only one battery is used, remote backup clearing of line and substation faults is 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) The 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.

6.2.5.2.4 AC Auxiliary Power

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

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

6.2.5.2.5 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.

6.2.5.2.6 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 (PLC) is desirable to reduce false trips from failure to block; and

 (c) Split up PLC 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.

6.2.5.2.7 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) Shielded cable may be necessary for certain relay and SCADA applications;

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

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

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

(e) No splice in any wire or cable; and

(f) All cables terminated on terminal blocks.

6.2.5.2.8 Environment

(1) Means shall be employed to maintain environmental conditions that are favorable to the correct performance of the protective relay system. 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.

6.2.5.3 Specific Application Considerations

6.2.5.3.1 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. The protective relay system 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 system, including breaker failure.

(2) Transmission line protection should consist of:

(a) Primary phase and ground protection over a communications channel;

(b) Backup relaying with at least two zones of phase protection;

(c) Backup relaying with at least two zones of ground protection, or backup relaying with ground directional overcurrent relaying (time delay and instantaneous);

(d) Ground chain protection 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;

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

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

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

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

(i) Fuses shall not be used in the 3Vo polarizing supply for ground relays; and

(j) The setting for synchronization check relays should be based on system studies that identify the voltage angles necessary for a successful re-close.

6.2.5.3.2 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) The protective relay system 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. The protective relay system 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 69kV; and

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

6.2.5.3.3 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 or solid state fault 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.

6.2.5.3.4 Generator Protection and Relay Requirements

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

(2) Generators 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 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 system 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 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 shall provide ERCOT with the operating characteristics of any generating unit's equipment protective relay system or controls that may respond to temporary excursions in voltage with actions that could lead to tripping of the generating unit.

6.2.5.3.5 Automatic Under-Frequency Load Shedding (UFLS) Protection Systems

(1) Automatic Under-Frequency Load Shedding (UFLS) systems are classified as protective relay systems. The maintenance requirements, discussed in Section 6.2.4, 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 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, Requirements for Under-Frequency Relaying.

(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 a UFLS operation is not currently utilized in ERCOT.

6.2.5.3.6 Automatic Under-Voltage Load Shedding (UVLS) Protection Systems

(1) Automatic Under-Voltage Load shedding (UVLS) systems are classified as protective relay systems. The maintenance requirements, discussed in Section 6.2.4, 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. 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 and to prevent false tripping.

(8) In addition, Generation Resources must be designed to remain connected to the transmission system during the following operating conditions:

(a) Generator 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 terminal voltage deviations exceed 5% but are within 10% of the rated design voltage and persist for less than 10.0 seconds;

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

(d) A transmission system fault (three-phase, single-phase or phase-to-phase), but not a generator bus fault, is cleared by the protection scheme coordinated between the Generation Entity and the TSP on any line connected to the generator's transmission interconnect bus, provided such lines are not connected to induction generators described in item (9), Protocol Section 3.15, Voltage Support.

(9) Generating Resources required to provide Voltage Support Service 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 that over-excitation protection only operates 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.

ERCOT Nodal Operating Guides

Section 7: Telemetry and Communication

April 1, 2009

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

---

7 Telemetry and Communication

7.1 ERCOT Wide Area Network

(1) ERCOT interfaces with each Qualified Scheduling Entity (QSE) and Transmission Service Provider (TSP) over a Wide Area Network (WAN). ERCOT is responsible for the configuration, maintenance, and management of the communications hardware required to support WAN connectivity. This includes, but is not limited to, ERCOT issued routers, switches, Channel Service Units/Data Service Units (CSU/DSUs), and out-of-band management equipment. The ERCOT WAN is a fully redundant, highly available network designed for Real Time data transport and is split in to two separate private networks; a Multiprotocol Label Switching (MPLS) network and a Point-to-Point (PTP) network. See Figure 1, ERCOT Wide Area Network.

(2) The MPLS network is provisioned with connectivity to each WAN participant. The primary purpose of the MPLS network is to facilitate Transmission Control Protocol/Internet Protocol (TCP/IP) connectivity between ERCOT and the market for critical market data, most notably Inter-Control Center Communication Protocol (ICCP) and applications programming interface (API) data.

(3) The PTP network is provisioned with adequate Digital Signal "zero" (DS0) channels to support specific Market Participant requirements. The PTP network's main function is to provide voice communication to the Market Participant. Each Market Participant will be allocated the appropriate number of DS0s to support their particular configuration. ERCOT will monitor utilization and will make final determination of system requirements. The PTP network is also configured to provide redundancy to the MPLS network. In the event of an MPLS network failure, the PTP network is designed to route IP data traffic.

(4) The ERCOT WAN provides communication for the following:

(a) Real Time telemetry data exchange for wholesale operations, frequency control, and transmission security;

(b) Operational voice communications for both normal and emergency use. The ERCOT WAN supports off-premise exchanges (OPX) with ERCOT's control facilities and the ERCOT hotlines; and

(c) Data exchange to support API routines. These include power scheduling, operating plans, outage requests, dispatch instructions, posting of information and other applications.

7.1.1 ERCOT Responsibilities

ERCOT's responsibilities include the following:

(1) Supply Customer Premises equipment (i.e. equipment at Market Participant facilities for the WAN) including routers, CSU/DSUs, Local Area Network (LAN) switch/hub and all support equipment for management purposes;

(2) Order and provision of local loop, network access point and transport;

(3) Provide 24-hour network monitoring and management;

(4) Provide 24x7 maintenance, with 4-hour response, for all ERCOT equipment located at Market Participant site; and

(5) The ERCOT Helpdesk will be the single point of contact for all network issues, and the ERCOT Helpdesk will provide periodic updates to the Market Participant until the issue is resolved.

7.1.2 QSE and TSP Responsibilities

QSE and TSP Responsibilities include the following:

(1) TSPs and QSEs whose facilities connect to the ERCOT WAN are required to sign an agreement with ERCOT governing installation, operation and maintenance of the WAN hardware. Appropriate WAN documents can be obtained by contacting the ERCOT Account Manager

(2) ERCOT WAN participants shall provide physical security systems compliant with the applicable Critical Infrastructure Protection (CIP) requirement of the North American Electric Reliability Corporation (NERC) Reliability Standards.

(3) Any TSP or QSE facility, whether primary or back-up, will be required to connect directly to the ERCOT WAN; this includes connectivity to both the MPLS and PTP networks. The WAN connection will terminate at the Market Participant’s control center.

(4) Market Participants that serve both TSP and QSE functions at one location will only require one ERCOT WAN connection as defined in Section 7.1, ERCOT Wide Area Network, at that location.

(5) If a TSP and QSE share a centralized private branch exchange (PBX), separate OPX circuits will be terminated for each participant.

(6) Each Market Participant is required to extend the ERCOT OPX and Hotline voice circuits into its system operations desk that is staffed continuously. ERCOT will deliver the OPX and Hotline to a channel bank provided by the Market Participant. The OPX and Hotline voice circuits are transported on separate Digital Signal Level 0 (DS0) channels. In the event a Market Participant represents other Entities through an agency agreement approved by ERCOT, each Entity represented must have dedicated OPX circuits. In these cases, a single Hotline button will be used for the Market Participant and all of the represented Entities. It is the Market Participant’s responsibility to deliver the Hotline and the OPX to the Market Participant’s system operations desk in a manner that reasonably assures continuous communication with ERCOT and is not affected by PBX features such as automatic transfer or roll to voice mail. The demarcation point for all voice circuits is the Market Participant’s channel bank.

(7) Each TSP and QSE must provide internal facilities and communications to collect and furnish data and voice signals to the ERCOT WAN as required by the ERCOT Protocols. For TSPs these include, but may not be limited to, voice communications, ICCP, and Supervisory Control And Data Acquisition (SCADA) for substations and other Transmission Facilities. For QSEs these include, but may not be limited to, voice communications, ICCP, and SCADA for Resources.

(8) QSEs and TSPs shall supply, implement, and maintain all data and voice communication facilities required to fulfill the obligations set forth in these Operating Guides.

(9) ERCOT WAN participants shall provide adequate physical facilities to support the ERCOT WAN communications equipment. The physical facilities and communications equipment requirements include:

(a) Provide an analog business phone line or PBX analog extension for troubleshooting and maintenance of equipment;

(b) Provide a height of 24” of rack space in a 19” wide rack;

(c) Provide two separate UPS single-phase 115 VAC 20 amp circuits, each with four receptacles in the 19” rack listed above;

(d) Provide building wiring from circuit termination to equipment rack;

(e) Within 24-hours notice, provide ERCOT employees or contractors access to the communication facility;

(f) Within one-hour notice, provide emergency access to the facility to ERCOT employees or contractors;

(g) Provide on site personnel to escort ERCOT employees or contractors;

(h) Provide a firewall or router, located at the Market Participant site, for the network address translation of internal Market Participant addresses to external addresses on the ERCOT LAN;

(i) Provide connectivity from Market Participant firewall or router to ERCOT LAN located at Market Participant site. Market Participants are responsible for their own security through this connection;

(j) Provide a channel bank with at least one T1 interface and four Foreign Exchange Station (FXS) ports. Connect FXS (e.g. PBX, key system) to the appropriate equipment. On the digital T1 stream, levels for voice are zero dpm for transmit and receive;

(k) Dual cable entrances to Market Participant, connecting to different Telco Central Offices is highly recommended; and

(l) Provide ERCOT with internal IP addressing scheme as needed for network design. This will be kept confidential.

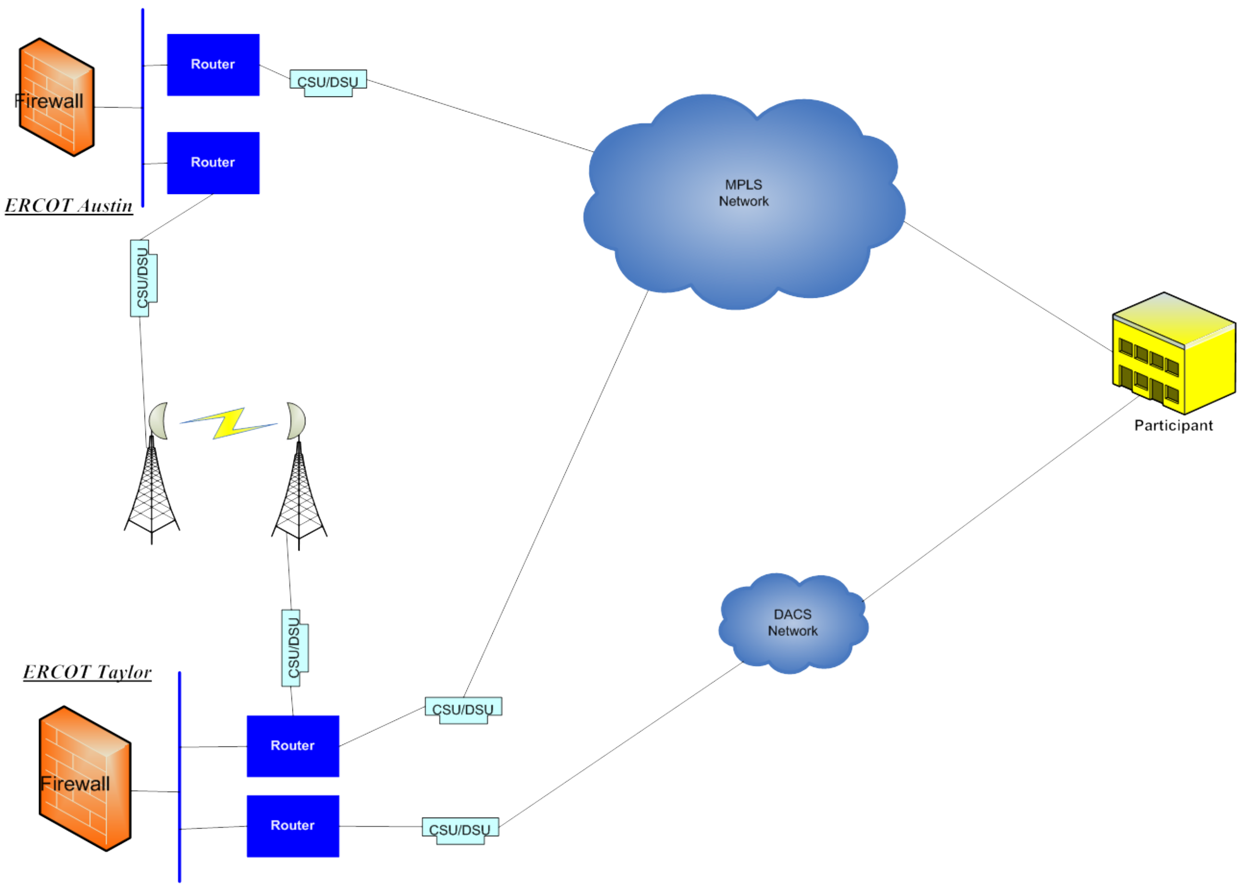


Figure 1 ERCOT Wide Area Network Overview

7.1.3 Joint Responsibilities (Maintenance and Restoration)

Joint responsibility of ERCOT WAN-connected Market Participants and ERCOT include the following:

(1) Coordinate maintenance and restoration activities so its reliability is not compromised;

(2) All primary and back-up circuits shall be tested annually or as otherwise requested by ERCOT for end-to-end performance;

(3) ERCOT will specify test procedures for hotline and any back-up or alternate path voice circuits;

(4) A Market Participant must be able to transmit and receive test voice signals. The test equipment must be capable of transmitting, receiving, and measuring frequency and decibel

level. This will allow ERCOT and the Market Participant to isolate circuit and equipment problems for quick resolution and restoration of voice communication; and

(5) Scheduled maintenance of any WAN hardware/software shall be coordinated between ERCOT and the affected Market Participant. The Market Participant shall provide reasonable outage windows for ERCOT support personnel to upgrade and repair equipment.

7.2 ERCOT ICCP Interface

The Inter-Control Center Communication 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

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 prescribed by the TAC approved Telemetry Standards located on the ERCOT Market Information System (MIS) Public Area. 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.

7.3 Telemetry

(1) Qualified Scheduling Entity (QSE) and Transmission Service Provider (TSP) control centers required to supply Real Time telemetry data to ERCOT shall use an Inter-Control Center Communication 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/or 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 ICCP Nodal Communications 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 and the Technical Advisory Committee (TAC) approved Telemetry Standards.

(3) QSEs, Resources and TSPs are required to provide power operation data to ERCOT according to the Protocols and the ERCOT ICCP Nodal Communications 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 to QSEs in accordance with the Protocols and the ERCOT Nodal ICCP Communications 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 to the TSP in accordance with the Protocols and the ERCOT Nodal ICCP Communications 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 Market Participants of all available data.

7.3.3 Data from QSEs and TSPs to ERCOT

(1) Each TSP and QSE shall provide telemetered measurements on modeled Transmission Elements as required by the Protocols and the ERCOT Nodal ICCP Communications Handbook.

(2) QSEs and TSPs shall provide Real-Time monitoring of power system quantities to ERCOT as defined in the Protocols and the ERCOT Nodal ICCP Communications Handbook. ERCOT shall work with TSPs and QSEs 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 TSP shall notify ERCOT as soon as practicable when telemetry will not be available or is unreliable for operational purposes. When ERCOT receives notification, the associated points shall be removed from the TAC approved Telemetry Standard performance metrics calculations.

(5) Each QSE and TSP shall notify ERCOT as soon as practicable when telemetry is returned to normal state.

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 TSP and QSE Telemetry Restoration

Real Time telemetry data shall be restored using criteria and procedures as established by the TAC approved Telemetry Standard.

7.3.5 General Telemetry Performance Criterion

All Real Time telemetry as required by the Protocols shall meet the State Estimator Performance and the TAC approved Telemetry Standards.

7.4 Calibration and Testing of Telemetry Responsibilities

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, the Technical Advisory Committee (TAC) approved Telemetry Standards, and Good Utility Practice.

ERCOT Nodal Operating Guides
Section 8
Attachment A

Detailed Black Start Information

November 1, 2007

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

This attachment provides the minimum information necessary to be used in conjunction with the ERCOT Black Start Plan. Each Transmission Operator (TO), Qualified Scheduling Entity (QSE), and 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 TO loses voltage on all busses and incoming transmission lines, then operators should assume there is a system wide blackout. The TO should immediately notify ERCOT if possible. Contracted Black Start Resources should implement Black Start procedures and establish contact with their TOs. Other Generation Resources should contact their QSEs and then wait for instructions from the TOs. If possible, ERCOT will update TOs and QSEs concerning ERCOT System status by use of the 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 power plant facilities 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) Power plant availability and time required to restart;
- (e) Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants;
- (f) Status of transmission breakers and sectionalizing equipment at tie points to other areas;
- (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 collapse within the ERCOT System. As part of the initial assessment after a partial or

complete system collapse, communication facilities should be tested and verified. It is possible, especially in case of a total ERCOT collapse, that communications with out-of-state QSEs 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 should:

(i) Verify or establish communication paths with TOs;

(ii) Verify or establish communications paths with QSEs;

(iii) Verify integrity of ERCOT Hotline;

(iv) Periodically disseminate information to TOs and QSEs; and

(v) Direct implementation of Black Start Plan in blacked out areas.

(b) The TO operators should:

(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 plants necessary to the restoration of the system in their area.

(c) The QSE should:

(i) Contact ERCOT to report status of Generation Resources within ERCOT;

(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 should:

(i) Isolate their Black Start Resource from the transmission system;

(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.

(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 should ensure that conversations are concise and effective.

Preparing for System Restoration

(1) Orderly restoration will usually require sectionalizing the de-energized parts of the 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 should be given to restoring offsite power to nuclear plants;

(b) Ensure that blocks of load to be energized are sized to minimize the problems of cold load pickup; and

(c) Operators should verify that their switching orders as well as any standing emergency switching orders have been completed.

Bringing Up Plants

(1) First priority should be given to preventing damage to power plant equipment and to restoring offsite power to nuclear power plants. Secondly, attention should be given to preparing units that can come on line most rapidly. All operators should remember that large steam plants will need an outlet for the minimum generation requirement soon after coming on line.

(2) A plant with contracted Black Start capability has procedures to begin the process of bringing its units back up when the switchyard and all incoming transmission lines are de-energized. The plant shall not synchronize or pick up load without communicating with the TO to which it is connected.

(3) A plant without Black Start capability should have a written procedure in place to begin preparing the plant to be energized from an external line. When the TO has energized the plant switchyard it will contact the Generation Resource directly and the QSE as soon as practical. The TO will coordinate starting of large motors, bringing plants on line, and synchronizing plants with the rest of the transmission grid.

(4) Plant operators will be controlling system frequency during the recovery period and must keep it between trip points for unit's under-frequency and over-frequency relays. It is preferable to use the units with lowest under-speed trip for initial restoration.

(5) Automatic voltage regulators should be placed in service as soon as practical after bringing units on line and should remain in service to improve machine stability.

(6) As soon as possible, after bringing a unit on line, automatic governor controls should be placed in the "automatic" position to insure instantaneous governor response to changes in frequency.

Picking Up Lines

(1) Ties between nearby power plants should be established as soon as possible. Priority should be given to restoring at least one circuit to nuclear power plants 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 plants 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 0.3 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 unit 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 should be given to restoring offsite power to nuclear power plants. 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 unit 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 system again. There should be sufficient time between switching operations to allow the units to recover from the sudden increase in Load.

(5) The Operators in TO control rooms should exercise caution when loading a single unit to more than 50% of its control range until additional units have been brought back on-line in that island. Generally, no unit should be loaded to more than 80% of its normal rating until system conditions return to normal.

(6) Since each plant may be operating independently, plant operators will have to monitor and adjust their unit's 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 units 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 should have field personnel in area islands to check breakers at each end of a line being used to synchronize between islands to insure 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 point of interconnection. 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 system status information, and facilitating communication between Market Participants. ERCOT will also monitor the changes in generation 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 plants 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 inter-company islands ERCOT will designate the entity responsible for frequency control in the combined islands. Initially this may be a single plant. 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. As inter-company islands are synchronized ERCOT will approve the addition of generation and Load to the system. No additions should be made without that approval.

CONSIDERATIONS FOR BLACK START TESTING

(1) ERCOT shall maintain a record of contracted Black Start Generation Resources within ERCOT 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 NERC Reliability Standards. A current Black Start Generation Resource Test Results Form will be provided with the RFP for Black Start Service distributed by ERCOT.

(2) The owner or operator of each Black Start Generation Resource shall demonstrate through the testing procedures outlined in Protocol Section 8.1.2.2.6, System Black Start Capability, that the Generation Resource can perform its intended functions as required in the system restoration plan. ERCOT may also order random simulation or testing of Black Start capabilities. Documentation of the analysis shall be provided to NERC on request per 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, TOs, and Resource Entities.

(2) ERCOT System Operators shall review these documents on a regular basis. It is suggested that the ERCOT Black Start Plan include as a minimum the following elements:

- (a) Strategies and guidelines for ERCOT restart.
- (b) Identification of the relationships and responsibilities of the QSEs, TOs, and Market Participant's personnel necessary to the restoration.
- (c) Identification of Black Start Generation Resources including:
  - (i) Generation Resources.
  - (ii) Transmission Facilities.
  - (iii) Communication resources.
  - (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 Entity, QSE, and TO operators and their respective communications personnel.
- (i) Procedures for Public Notification.
- (j) Procedures for return to Market Operations.

(3) Transmission Operators shall maintain a local Black Start Plan that is coordinated with the ERCOT Black Start Plan, but provides additional local detail. The TO Black Start Plan should include sections on the Black Start Scope, Communication Process, and Operations as outlined below.

(a) A Scope Section of the TO Black Start Plan shall provide the main objectives, responsibilities, and expected actions of the TO and other market Entities in the event of system blackout. This section should address at least the following items:

(i) Roles and Responsibilities - Identify the TO's role as well as those of Generation Resources and ERCOT in the case of a blackout.

(ii) Identifying the blackout event - Clearly state how a blackout event will be recognized and identify actions the TO operator needs to perform in order to initiate restoration as well as actions that should be expected from ERCOT and other Market Participants.

(iii) Assessing and verifying communication capabilities - Include a procedure for assessing communication capabilities and a plan for dealing with failures of various systems.

(iv) Transferring control away from ERCOT - Acknowledge that, in the event of a blackout, the TO will have ERCOT's authority to bring Generation Resources on line and energize 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 blackout condition has been identified.

(v) Starting the Black Start Generation Resources- Primarily rely on contracted Black Start Generation Resources in restoring the system. However, the TO plan should also account for non-contracted Black Start unit capabilities and, if possible, incorporate these resources.

(vi) Building stable island(s) - Primarily focus on building stable islands with the ultimate goal of reaching synchronization points. TO plans should also consider that while larger islands are more stable they might be more difficult to synchronize with neighboring islands.

(vii) Reaching synchronization points - Focus on restoring the system and not restoring service to customers. The primary focus of the TO plan should be on building a stable island that reaches a designated synchronization point.

(viii) Synchronizing islands - Instruct operators to 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. For intra-company islands the plan should contain instructions for adding Load and Generation Resources.

(ix) 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, but it will be at the direction of ERCOT as specified in the Strategy section of this plan.

(b) A communications process section of the TO plan should address at least the following items:

(i) ERCOT contact information.

(ii) List of contracted Black Start Generation Resources within the TO footprint.

(iii) Plant and QSE contact information and location within system.

(iv) List of non-contracted Black Start Generation Resources identified within the TO Black Start Plan.

(A) Plant and QSE contact information and location within the TO's operating system.

(v) List of additional generating plants included in the Black Start Plan.

(A) Plant and QSE contact information and location within the TO's operating system.

(B) Start-up characteristics of each plant.

(vi) List and location of neighboring TOs;

(A) Contact information and tie points within the TO's operating system.

(c) An operations section of the TO plan should address at least the following items and include subsection for operations of each island:

(i) Black Start Generation Resource start-up and Load pick up procedure.

(ii) Next start Generation Resource start-up and Load pick up procedure.

(iii) Loads

(A) Critical loads in each island.

(B) Load critical to generation (fuel supply).

(iv) Transmission paths;

(A) Switching procedures for primary transmission corridor.

(B) Switching procedure for secondary transmission corridor.

(C) One line diagram of primary and secondary corridor from Black Start Generation Resource to synchronization points.

(D) Special considerations or procedures for switching lines belonging to another TO.

(v) Synchronization points;

(A) Location and ownership of each synchronization point.

(B) Synchronization procedures and special requirements for each location.

ERCOT Nodal Operating Guides
Section 8
Attachment B

Relay Misoperation Report

August 1, 2010

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

Relay Misoperation Report

Relay misoperations shall be reported in any format compatible with ERCOT (i.e., Microsoft Excel ©, Microsoft Word ©, or PDF) except where a specific format is requested. All fields of data specified in the table below shall be included in the report. The file shall include the "Field Names" listed in the table below as headers for each field and the data size/format shall match "Size or Format" specified in the table below.

Field Name	Type	Size or Format	Description
Misop_Date	Date	mm/dd/yyyy	The date that misoperation occurred.
Misop_Time	Time	hh:nn:ss	The time at which misoperation occurred in 24-hour format – this could be time marked by the relay if it is synchronized with GPS clock, time noted by each facility owner's or operator's operations control center.
Time_Zone	Text	50	Define the standard time of the misoperation time noted (i.e. GMT, CT, EST, etc.).
Utility	Text	25	Name of the facility owner.
Voltage	Text	10	Transmission voltage (345 kV, 138 kV, 69 kV, etc.).
Protected_Equipment	Text	25	The Transmission Element (line, autotransformer, bus, etc.) protected by the protection scheme.
Substation	Text	50	Name of the substation where the misoperated element or equipment is located.
Protection_Scheme	Text	25	Type of protection scheme applied (i.e. Differential, DCB, SPS, Step distance, etc.).
Equipment_Name	Text	50	Specific description of the protected transmission equipment.
CB_Number	Text	50	Unique circuit breaker number assigned or used by the facility owner that effected the actual isolation.
Fault_Type	Text	50	Type of fault occurred (L-L, L-G, L-L-G, 3L-G, etc. If the misoperation occurred for a non-fault condition, note this field with 'N/A').
Communication_Method	Text	50	Type of communication method used for the protection scheme (i.e. Pilot wire, fiber, power-line carrier, etc.).
Manufacturer	Text	50	Relay Manufacturer's name.
Relay_Type	Text	50	Relay Type or style name (i.e. SEL-321, REL-512, CO-9, etc.).
Relay_Style	Text	50	Relay model number.
Misop_Category	Text	50	Relay events constitute as reportable protective relay system misoperation as detailed in Section 6.2.3, Performance Analysis Requirements for ERCOT System Facilities.

Misop_Description	Text	32,767	Description of the protective element/scheme failure that caused the misoperation.
Investigation_Results	Text	32,767	Description of the analysis results from the misoperation review and any deficiencies identified.
Corrective_Action	Text	32,767	An action plan to correct any deficiencies identified in the investigation results or any additional action plan to avoid similar operations in the future.
Target_Date	Date	mm/dd/yyyy	Target date to implement the corrective action plan at the terminal(s) where the misoperation(s) occurred. This could also be the date that the corrective action plan was implemented.
Recommendation	Text	32,767	System wide corrective action plan or long term solution to avoid similar misoperations (i.e. design changes, equipment replacements, etc.).
Report_By	Text	25	Individual who completed the report.
Phone	Text	50	Business phone number of the individual who completed the report.
Report_Date	Date	mm/dd/yyyy	The date at which the report was completed (i.e. when corrective action was implemented).

ERCOT Nodal Operating Guides
Section 8
Attachment C

Turbine Governor Speed Tests

November 1, 2007

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

TURBINE GOVERNOR SPEED REGULATION TEST FOR MECHANICAL-HYDRAULIC GOVERNOR

GENERAL INFORMATION

Unit Code (16 character): ________________ 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

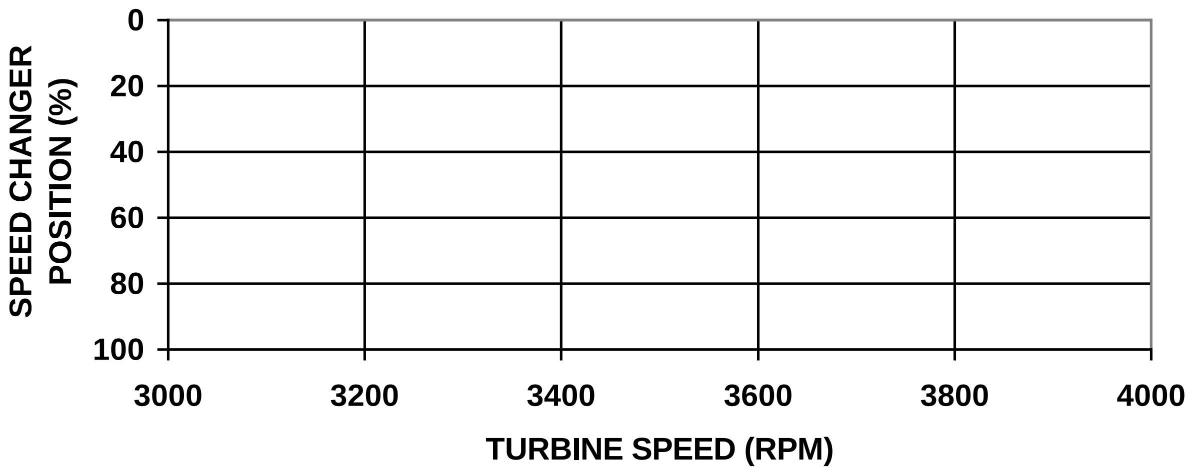
$$Rs = \frac{(E - F) \times 100}{3600}$$

[1] Westinghouse recommends using only this test.

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.

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:____

SUBMITTAL

Resource Entity Representative: ______________________________

QSE Representative: ______________________________

Date submitted to ERCOT Rep.: ______________________________

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.

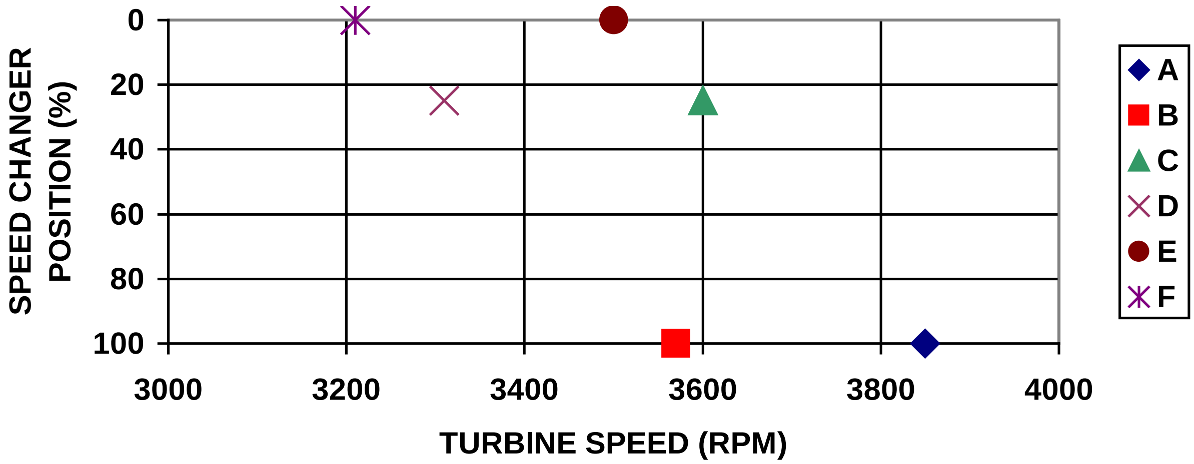
Steady State Speed Regulation at Low-Speed Stop

$$Rs = \frac{(E - F) \times 100}{3600} = \frac{(3500 - 3210) \times 100}{3600} = 8.06\%$$

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.
F = Speed with speed changer set at low-speed stop and when governing valves just reach wide-open position.

[2] Westinghouse recommends using only this test.



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 character): ________________ Location (County) :______________________

Unit Name: ____________________________ Date of test: ____________________________

QSE:__________________________________ Resource Entity: ________________________

Turbine Governor Speed Regulation Test Procedures

a. (a) Simulate unit on line and turbine speed at 3600 RPM.

b. (b) Set load reference at minimum value.

c. (c) Monitor valve demand signal and record as value 'A' (in %).

d. (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. (e) Set speed at 3600 and load reference at maximum value.

f. (f) Monitor valve demand signal and record as value 'D' (in %).

g. (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: ____

____

____

____

____

SUBMITTAL

Resource Entity Representative: ____

QSE Representative: ____

Date submitted to ERCOT Rep.: ____

DEFINITIONS

System Frequency Response	This response is a function of three key variables; the system's composite governor droop, the percent of spinning capacity which is actually providing governor response, and the frequency response characteristic 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. 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 turbine 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 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. With one method, the turbine governor (G.E.) or control (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. With the other 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.

ERCOT Operating Guides
Section 8
Attachment D

Seasonal Unit Net Real Power Capability Verification

November 1, 2007

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

*** All References to Protocols and Operating Guides throughout this document are to Nodal Protocols and Nodal Operating Guides*

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

SUBMITTAL

Resource Entity Representative: ____

QSE Representative: ____

Date submitted to ERCOT Rep.: ____

ERCOT Nodal Operating Guides
Section 8
Attachment E

May 1, 2010

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

Attachment intentionally left blank

ERCOT Nodal Operating Guides
Section 8
Attachment F

Seasonal Hydro Responsive Reserve Net Capability Verification

November 1, 2007

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

*** All References to Protocols and Operating Guides throughout this document are to Nodal Protocols and Nodal Operating Guides*

Seasonal Hydro 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
Section 8
Attachment G

Load Resource Tests

August 1, 2010

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

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 Resource's providing Responsive Reserve Service
** 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 Resource's 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 Responsive Reserve 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 TELEMTERED 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.

ERCOT Nodal Operating Guides
Section 8
Attachment H

Unit Alternative Fuel Capability

August 1, 2010

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

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

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%**	
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

Section 9: Monitoring Programs

June 1, 2010

(Effective Upon the Nodal Operating Guide Transition Plan's Texas Nodal Market Implementation Date as prescribed by zonal Operating Guide Section 1.3.7, Process for Transition to Nodal Operating Guide Sections)

9- 9 MONITORING PROGRAMS

9.1 QSE and Resource Monitoring Program

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.

9.1.1 Testing

[Placeholder]

[NOGRR025: Replace Section 9.1.1, Testing, above, with the following upon system implementation:]

9.1.1 Testing

ERCOT shall produce reports annually which summarize:

(1) Capability test results for the applicable Resources. These results must be provided to ERCOT by the QSE for the Resource. The QSE shall provide these results to ERCOT upon completion of capability testing of the Resource.

(2) Test results of Emergency Interruptible Load Service (EILS) Loads by Resource and QSE; and

(3) Test results for Load Resources.

9.1.2 Reactive Testing for Generation Resources

[Placeholder]

[NOGRR025: Replace Section 9.1.2, Reactive Testing for Generation Resources, above, with the following upon system implementation:]

9.1.2 Reactive Testing for Generation Resources

(1) The QSE shall provide the following information:

(a) Unit name;

(b) QSE;

(c) Date;

(d) Time;

(e) Tested generation real power capability;

(f) Reported time; and

(g) Corrected Unit Reactive Limit (CURL) and Unit Reactive Limit (URL).

(2) ERCOT shall produce reports annually which describe when the last lagging reactive capability test took place, what the MW and Mega Volt-Ampere Reactive (MVAr) outputs were during the test period, how long the output was held, and a minimum of four MW/MVAr pairs describing the CURL of the unit and any limiting conditions that created the need for a CURL. This data shall be provided by the QSE to ERCOT when reactive testing indicates a change in unit reactive capability and at a minimum of once every two years.

9.1.3 Real-Time Data

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 and the Technical Advisory Committee (TAC)-approved Telemetry Standards.

[NOGRR025: Replace Section 9.1.3, Real-Time Data, above, upon system implementation:]

9.1.3 Real-Time Data

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. Individual point performance shall be posted to the MIS Certified Area.

(a) Telemetry performance:

(i) ERCOT shall produce quarterly reports describing telemetry performance as defined in the Protocols and the Technical Advisory Committee (TAC)-approved Telemetry Standards.

(b) Communication system performance:

(i) ERCOT shall produce monthly reports describing the reliability of each participants Inter-Control Center Communications Protocol (ICCP) data link to ERCOT as defined in the Protocols and the TAC-approved Telemetry Standards.

(ii) ERCOT shall produce monthly reports describing ICCP link up/down statistics.

9.1.4 Compliance with Valid Dispatch Instructions

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 Deployment Performance.

[NOGRR025: Replace Section 9.1.4, Compliance with Valid Dispatch Instructions, above with the following upon system implementation:]

9.1.4 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 Deployment Performance. ERCOT shall produce yearly reports of QSE and Resource-specific regulation performance metrics as required in the Protocols.

(2) ERCOT shall produce a report for any system-wide deployment of Load Resources or EILS, on an event basis, within one month after the event occurs and shall post it to the MIS Secure Area.

9.1.5 Resource Facilities Network Operations Model Update Implementation Monitor

[Placeholder]

[NOGRR025: Replace Section 9.1.5, Resource Facilities Network Operations Model Update Implementation Monitor, above with the following upon system implementation:]

9.1.5 Resource Facilities Network Operations Model Update Implementation Monitor

(1) ERCOT shall prepare monthly reports summarizing the Network Operations Model updates by Resource Facilities. These reports shall include the number of Notices of interim updates submitted to the Public Utility Commission of Texas (PUCT) and the Independent Market Monitor (IMM) as accumulated by QSE due to the actions or inactions of the associated QSE for Network Operations Model Change Requests (NOMCRs) not meeting the timeline pursuant to Protocol Section 3.10.1, Time Line for Network Operations Model Change Requests. These reports shall be delineated by

category and owner including reasons for the interim updates. Interim updates caused by ERCOT (i.e. server unavailability, Network Model Management System (NMMS) component failure, site failover, loss of data, staff overload, weather, etc.) shall be reported and attributed to ERCOT.

(2) ERCOT shall post reports on the MIS Secure Area.

9.1.6 Resource Outage Reporting

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.

(1) ERCOT shall post a confidential report of total number of Outages reported through the Texas Market Link (TML) 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 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.

9.1.7 Backup Control for Resource Energy Deployment

[Placeholder]

[NOGRR025: Replace Section 9.1.7, Backup Control for Resource Energy Deployment, above, with the following upon system implementation:]

9.1.7 Backup Control for Resource Energy Deployment

ERCOT shall produce a report identifying the date of backup control plan testing and the success or failure of that test for ERCOT and QSEs. Backup control plan tests shall be conducted at least annually.

9.1.8 Qualified Staffing Requirement

[Placeholder]

[NOGRR025: Replace Section 9.1.8, Qualified Staffing Requirement, above, with the following upon system implementation:]

9.1.8 Qualified Staffing Requirement

A QSE shall maintain a continuously operating scheduling center staffed with qualified personnel with the authority to commit and bind the QSE. ERCOT shall report to the Texas Regional Entity (TRE), instances of suspected non-performance.

9.1.9 Automatic Voltage Regulator (AVR)

[Placeholder]

[NOGRR025: Replace Section 9.1.9, Automatic Voltage Regulator (AVR), above with the following upon system implementation:]

9.1.9 Automatic Voltage Regulator (AVR)

(1) ERCOT shall record QSE provided Automatic Voltage Regulator (AVR) test reports for Resources which must include:

(a) The minimum and maximum excitation limiters settings and associated time limits;

(b) Volts/hertz settings;

(c) Gain and time constants;

(d) Date tested; and

(e) Voltage regulator control mode;

(2) ERCOT shall produce a monthly report that will identify Resources for which test reports have not been submitted within the last 60 months.

(3) ERCOT shall produce a monthly report listing the Generation Resources that are not meeting AVR availability for periods in which they are required to provide Voltage Support Service (VSS) as described in paragraph (4) of Protocol Section 3.15.3, QSE Responsibilities Related to Voltage Support. The AVR criteria are described in

paragraph (2) of Section 2.7.4.1, Maintaining System Voltage.

9.1.10 Current Operating Plan Metrics for QSEs

ERCOT shall report in the Day-Ahead when the reserved capacity of a QSE's Resources in the Operating Day Current Operating Plan (COP) at 1430 is not sufficient to supply Ancillary Service requirements for the upcoming Operating Day. ERCOT shall provide a monthly summary of the total days failed and total hours analyzed when the Resource's reserves are insufficient for any hours during an Operating Day pursuant to paragraph (2) of Protocol Section 8.1.2, Current Operating Plan (COP) Performance Requirements, and not excused due to exemptions contained in the Protocols.

[NOGRR025: Replace Section 9.1.10, Current Operating Plan Metrics for QSEs, above, with the following upon system implementation:]

9.1.10 Current Operating Plan Metrics for QSEs

(1) ERCOT shall report when a seven day Current Operating Plan (COP) has not been provided by the representing QSE for a Resource by 1500 each day. An event occurs when a QSE has not provided at least 153 hours of a Resource's operating plan to ERCOT by 1500. This report will be prepared monthly and posted on the MIS Secure Area.

(2) ERCOT shall report in the Day-Ahead when the reserved capacity of a QSE's Resources in the Operating Day COP at 1430 is not sufficient to supply Ancillary Service requirements for the upcoming Operating Day. ERCOT shall provide a monthly summary of the total days failed and total hours analyzed when the Resource's reserves are insufficient for any hours during an Operating Day pursuant to paragraph (2) of Protocol Section 8.1.2, Current Operating Plan (COP) Performance Requirements, and not excused due to exemptions contained in the Protocols.

9.2 TSP Monitoring Program

9.2.1 Rating Methodology Reporting Program

[Placeholder]

[NOGRR025: Replace Section 9.2.1, Rating Methodology Reporting Program, above with the following upon system implementation:]

9.2.1 Rating Methodology Reporting Program

Transmission Service Providers (TSPs) shall submit their equipment rating methodology to ERCOT in the first quarter of each year or provide notice to ERCOT that the rating methodology has not changed since the previous year. ERCOT shall keep records describing the rating methodologies of each TSP in the ERCOT Region. ERCOT shall prepare an annual report summarizing these rating methodologies and submit this information to the Texas Regional Entity (TRE) and the appropriate Technical Advisory Committee (TAC) subcommittee.

9.2.2 Real-Time Data Monitor

ERCOT shall produce reports describing Real-Time data performance of 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 and the TAC-approved Telemetry Standards.

[NOGRR025: Replace Section 9.2.2, Real-Time Data Monitor, above with the following upon system implementation:]

9.2.2 Real-Time Data Monitor

ERCOT shall produce reports describing Real-Time data performance of TSPs in the following areas. ERCOT shall post the summary report on the Market Information System (MIS) Secure Area. Individual point performance shall be posted to the MIS Certified Area.

(a) Telemetry performance:

(i) ERCOT shall produce quarterly reports describing telemetry performance as defined in the Protocols and the TAC-approved Telemetry Standards.

(b) Communication system performance:

(i) ERCOT shall produce monthly reports describing the reliability of each participant's Inter-Control Center Communications Protocol (ICCP) data link to ERCOT as defined in the Protocols and the TAC-approved Telemetry Standards.

(ii) ERCOT shall produce monthly reports describing ICCP link up/down statistics.

9.2.3 Transmission Outage Reporting

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.

(1) 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.

[NOGRR025: Add paragraph (2) to Section 9.2.3, Transmission Outage Reporting, above, upon system implementation:]

(2) ERCOT shall post reports for each transmission owner showing the percentage of the total number of Outages, by type, described in paragraph (1) above.

9.2.4 Transmission Service Provider (TSP) Network Operations Model Update Implementation Monitor

[Placeholder]

[NOGRR025: Replace Section 9.2.4, Transmission Service Provider (TSP) Network Operations Model Update Implementation Monitor, above, with the following upon system implementation:]

9.2.4 Transmission Service Provider (TSP) Network Operations Model Update Implementation Monitor

(1) ERCOT shall prepare monthly reports summarizing the Network Operations Model updates by TSPs. The report shall include the number of Notices of interim reports submitted to the Public Utility Commission of Texas (PUCT) and the Independent Market Monitor (IMM) as accumulated by TSP due to the actions or inactions of the associated TSP for Network Operations Model Change Requests (NOMCRs) not meeting the timeline pursuant to Protocol Section 3.10.1, Time Line for Network Operations Model Change Requests. These reports shall be delineated by category and owner

including reasons for the interim updates. Interim updates caused by ERCOT (i.e. server unavailability, Network Model Management System (NMMS) component failure, site failover, loss of data, staff overload, weather, etc.) shall be reported and attributed to ERCOT.

(2) ERCOT shall post reports on the MIS Secure Area.

9.2.5 Backup Control for TSPs

[Placeholder]

[NOGRR025: Replace Section 9.2.5, Backup Control for TSPs, above, with the following upon system implementation:]

9.2.5 Backup Control for TSPs

ERCOT shall produce a report identifying the date of backup control plan testing and the success or failure of that test for TSPs. Backup control plan tests shall be conducted at least annually.

9.3 ERCOT Monitoring Program

9.3.1 Transmission Control

ERCOT shall report State Estimator (SE) performance in accordance with the Protocols and the Technical Advisory Committee (TAC)-approved State Estimator Standards and post such report on the Market Information System (MIS) Secure Area.

(a) ERCOT shall produce monthly reports describing SE convergence and valid SE solution rates as described in Protocol Section 3.10.9.2, Telemetry and State Estimator Performance Monitoring.

(b) ERCOT shall produce monthly reports describing the MW differences between SE results and power flow results for identified congested Transmission Elements as approved by TAC.

(c) ERCOT shall produce monthly reports describing the MW differences between the SE results and telemetry for identified congested Transmission Elements as approved by TAC.

(d) ERCOT shall produce monthly reports describing the voltage differences between the SE results and telemetry for the voltage critical buses identified in accordance with the State Estimator Standards.

(e) ERCOT shall produce monthly reports describing the MW differences as defined in the State Estimator Standards.

(f) ERCOT shall produce monthly reports identifying the sum of MW flows around telemetered SE Buses 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.

[NOGRR025: Replace Section 9.3.1, Transmission Control, above, with the following upon system implementation:]

9.3.1 Transmission Control

(1) ERCOT shall prepare a report describing the operating violations on every transmission line and auto-transformer operated at voltages greater than 60 kV. These reports shall be provided to the Texas Regional Entity (TRE) and the appropriate Technical Advisory Committee (TAC) subcommittee.

(a) ERCOT shall prepare monthly reports on the following:

(i) Exceedance of system operating limits or power transfer limitations set by ERCOT to guard against post-contingency stability exceedance for over ten minutes;

(ii) N-1 exceedance of the applicable equipment ratings provided by Transmission Service Providers (TSPs), Qualified Scheduling Entities (QSEs), and Resources for over 30 minutes; and

(iii) N-0 exceedance detected during the month, the time duration of the loading above the applicable operating rating and the maximum exceedence level that occurred.

(2) Other transmission monitoring and control metrics:

(a) ERCOT shall prepare reports describing the number of Forced Outages by transmission owner by month.

(b) ERCOT shall post on the Market Information System (MIS) Secure Area its performance in processing Outage requests in accordance with the following table including justification for rolling Outages from one timeline to another:

Amount of time between the request for approval of the proposed Outage and the scheduled start date of the proposed Outage:	**ERCOT shall approve or reject no later than:**
Three days	1800 hours, two days before the start of the proposed Outage

Between three and eight days	1800 hours, three days before the start of the proposed Outage
Between nine days and 45 days	Four days before the start of the proposed Outage
Between 46 and 90 days	40 days before the start of the proposed Outage
Greater than 90 days	75 days before the start of the proposed Outage

(c) ERCOT shall post on the MIS Secure Area, by transmission owner, the number of rejection Notices. The report will include specific concerns that caused the rejection.

(d) ERCOT shall post on the MIS Secure Area, by transmission owner, the number of withdrawals of approved Outages.

(e) ERCOT shall post on the MIS Secure Area, by transmission owner, the number of approved Outages that were rescheduled by ERCOT.

(3) State Estimator (SE) Performance:

(a) ERCOT shall report SE performance in accordance with the Protocols and the TAC-approved State Estimator Standards and post such report on the MIS Secure Area.

(i) ERCOT shall produce monthly reports describing SE convergence and valid SE solution rates as described in Protocol Section 3.10.9.2, Telemetry and State Estimator Performance Monitoring.

(ii) ERCOT shall produce monthly reports describing the MW differences between SE results and power flow results for identified congested Transmission Elements as approved by TAC.

(iii) ERCOT shall produce monthly reports describing the MW differences between the SE results and telemetry for identified congested Transmission Elements as approved by TAC.

(iv) ERCOT shall produce monthly reports describing the voltage differences between the SE results and telemetry for the voltage critical buses identified in accordance with the State Estimator Standards.

(v) ERCOT shall produce monthly reports describing the MW differences as defined in the State Estimator Standards.

(vi) ERCOT shall produce monthly reports identifying the sum of MW flows around telemetered SE Buses 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

The following reports shall be posted on the MIS Secure Area:

(1) Resource control metrics:

(a) 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.

(2) Reliability Unit Commitments (RUCs) and deployments:

(a) 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).

[NOGRR025: Replace Section 9.3.2, System and Resource Control, above, with the following upon system implementation:]

9.3.2 System and Resource Control

The following reports shall be posted on the MIS Secure Area:

(1) Resource control metrics:

(a) 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.

(2) Reserve monitoring:

(a) ERCOT shall prepare monthly reports describing the dates and associated duration that ERCOT operated without sufficient operating reserves as defined in the Protocols.

(3) Reliability Unit Commitments (RUCs) and deployments:

(a) 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).

(4) Dynamically Scheduled Resource (DSR) performance and Resource with output schedule:

(a) ERCOT shall produce monthly reports for DSR Load signal failures of more than five minutes.

(b) ERCOT shall produce monthly reports noting the number of Resources on Output Schedule, by QSE.

(5) Reversal of Base Point instructions to Generation Resources from interval to interval:

(a) 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.

(6) ERCOT-wide Governor Response to Measurable Events:

(a) ERCOT shall develop monthly reports detailing ERCOT's System-wide governor response to each Measureable Event. ERCOT shall meet at all times the governor response criteria as described in Protocol Section 8.5.2, Primary Frequency Control Measurements.

9.3.3 Forecasting

[Placeholder]

[NOGRR025: Replace Section 9.3.3, Forecasting, above, with the following upon system implementation:]

9.3.3 Forecasting

(1) ERCOT shall report the Mean Absolute Percent Error (MAPE) each month for the following:

(a) The accuracy of each day's hourly system Load forecast posted at 0600 in the Day-Ahead of the Operating Day as compared with the actual average ERCOT Load for each hour of the Operating Day;

(b) Accuracy of the system hourly Load forecast used for Day-Ahead Reliability Unit Commitment (DRUC) compared to the actual average ERCOT Load for each hour of the Operating Day; and

(c) The accuracy of the hourly Load forecast for the following items compared to the average of the State Estimated Load at each Electrical Bus with a modeled Load for each hour:

(i) Hourly Load forecast used in the DRUC by Weather Zone;

(ii) Hourly Load forecast used in the Hourly Reliability Unit Commitment (HRUC) by Weather Zone; and

(iii) The accuracy of the Load forecast used in the DRUC for the largest MW and Megavolt Ampere (MVA) differences between the hourly Bus Load Forecast and the Real-Time Load at each Electrical Bus, by Weather Zone.

(2) ERCOT shall prepare monthly reports detailing:

(a) Day-Ahead forecast wind output, by Load Zone, by hour for the Operating Day, used in DRUC and at 0600 at the Day-Ahead.

(b) Actual wind output, aggregated by Load Zone, by hour of the corresponding Operating Day by Load Zone.

9.3.4 System Operating Constraints

[Placeholder]

[NOGRR025: Replace Section 9.3.4, System Operating Constraints, above, with the following upon system implementation:]

9.3.4 System Operating Constraints

ERCOT shall report the following comparisons with respect to Real-Time operations as they occur:

(a) Three consecutive days of a particular congestion constraint (constraints passed to SCED from Network Security Analysis (NSA)) in Real-Time not identified in the Day-Ahead Market (DAM);

(b) Two consecutive hours of a particular congestion constraint in Real-Time not identified in the HRUC process; and

(c) Two consecutive days of a particular congestion constraint in Real-Time not identified in the DRUC process.

9.3.5 Network Operations Model Update Implementation Statistics

[Placeholder]

[NOGRR025: Replace Section 9.3.5, Network Operations Model Update Implementation Statistics, above, with the following upon system implementation:]

9.3.5 Network Operations Model Update Implementation Statistics

ERCOT shall report monthly on the Network Operations Model update implementation statistics. The report shall include the total number of Network Operations Model Change Requests (NOMCRs) submitted, approved, rejected, withdrawn and any other status contained in the Protocols or defined by ERCOT.

9.3.6 Back-up Control Plan

[Placeholder]

[NOGRR025: Replace Section 9.3.6, Back-up Control Plan, above, with the following upon system implementation:]

9.3.6 Back-up Control Plan

ERCOT shall report, by exception, the Entities that have not submitted back-up plans by the end of the first quarter of each year in accordance with the following:

(a) ERCOT's back-up plan as required by paragraph (2)(h) of Protocol Section 8.2, ERCOT Performance Monitoring;

(b) QSE back-up plans submitted to ERCOT pursuant to Section 3.2.1, Operating Obligations; and

(c) TSPs' back-up plans submitted to ERCOT and the date that the plan was last updated pursuant to Section 3.9, Transmission Operators.

9.3.7 ERCOT Black Start Plan

[Placeholder]

[NOGRR025: Replace Section 9.3.7, ERCOT Black Start Plan, above, with the following upon system implementation:]

9.3.7 ERCOT Black Start Plan

ERCOT shall develop an annual Black Start Plan and post it on the MIS Certified Area.

9.3.8 Computer and Communication Systems Real-Time Availability and Systems Security

[Placeholder]

[NOGRR025: Replace Section 9.3.8, Computer and Communication Systems Real-Time Availability and Systems Security, above, with the following upon system implementation:]

9.3.8 Computer and Communication Systems Real-Time Availability and Systems Security

(1) ERCOT shall report each month the availability of its computer and communications systems to the appropriate TAC subcommittee. This report shall include availability statistics for ERCOT's Inter-Control Center Communications Protocol (ICCP) data links.

(2) 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.

(3) ERCOT shall also report each month the number of times the execution of SCED is terminated, by either manual action of the operator or program failure. The number of times of each event will be posted on the MIS Certified Area.

9.3.9 Voltage and Reactive Control Performance Monitoring

[Placeholder]

[NOGRR025: Replace Section 9.3.9, Voltage and Reactive Control Performance Monitoring, above, with the following upon system implementation:]

9.3.9 Voltage and Reactive Control Performance Monitoring

(1) ERCOT in coordination with the TSPs shall conduct studies to determine the nominal voltage set points across the ERCOT System for all Electrical Buses used for voltage support and shall post all Voltage Profiles annually on the MIS Secure Area.

(2) Transmission owners shall provide switching plans for automatically controlled reactors, capacitors, and other reactive controlled sources to ERCOT. For manually switched reactive devices, the transmission owner shall provide its guidelines for the operation of these devices. These plans and guidelines shall be posted annually to the MIS Secure Area and must be provided in accordance with the NOMCR or other prescribed process.

9.4 Ancillary Services Monitoring Program

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, QSE

Ancillary Service and Energy Deployment Compliance Criteria, will be posted on the Market Information System (MIS) Certified Area.

9.4.1 Hydro Responsive Testing

[Placeholder]

[NOGRR025: Replace Section 9.4.1, Hydro Responsive Testing,, above, with the following upon system implementation:]

9.4.1 Hydro Responsive Testing

ERCOT shall produce monthly reports of hydro responsive tests and verify results submitted.

9.4.2 Black Start Service Requirements for TSPs, QSEs, and Generation Resources

[Placeholder]

[NOGRR025: Replace Section 9.4.2, Black Start Service Requirements for TSPs, QSEs, and Generation Resources, above, with the following upon system implementation:]

9.4.2 Black Start Service Requirements for TSPs, QSEs, and Generation Resources

ERCOT shall produce annual reports containing record(s) of if and when a Black Start Plan was last received at ERCOT including Resources participating in Black Start Service and Transmission Service Provider (TSP) name and the date the plan was received. The Resource participating in Black Start Service and TSPs shall provide an updated Black Start Plan to ERCOT by the end of the first quarter and when the plan has changed.

9.4.3 Resource-Specific Responsive Reserve Performance

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, Regulation Service and Generation Resource Energy Deployment Performance.

9.4.4 Constant Frequency Control

[Placeholder]

[NOGRR025: Replace Section 9.4.4, Constant Frequency Control, above, with the following upon system implementation:]

9.4.4 Constant Frequency Control

ERCOT shall survey Qualified Scheduling Entities (QSEs) qualified to provide Regulation Services to attest that the QSEs have the capability to operate in constant frequency control mode. ERCOT shall post to the MIS Secure Area annual summaries of QSEs surveyed.

9.4.5 Resource-specific Non-Spinning Reserve

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.