ERCOT Nodal Operating Guides

April 1, 2009

(Effective Upon Texas Nodal Market Implementation)

ERCOT Nodal Operating Guide
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April 1, 2009

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Section 1: Overview

November 1, 2007

(Effective Upon Texas Nodal Market Implementation)

***** 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.

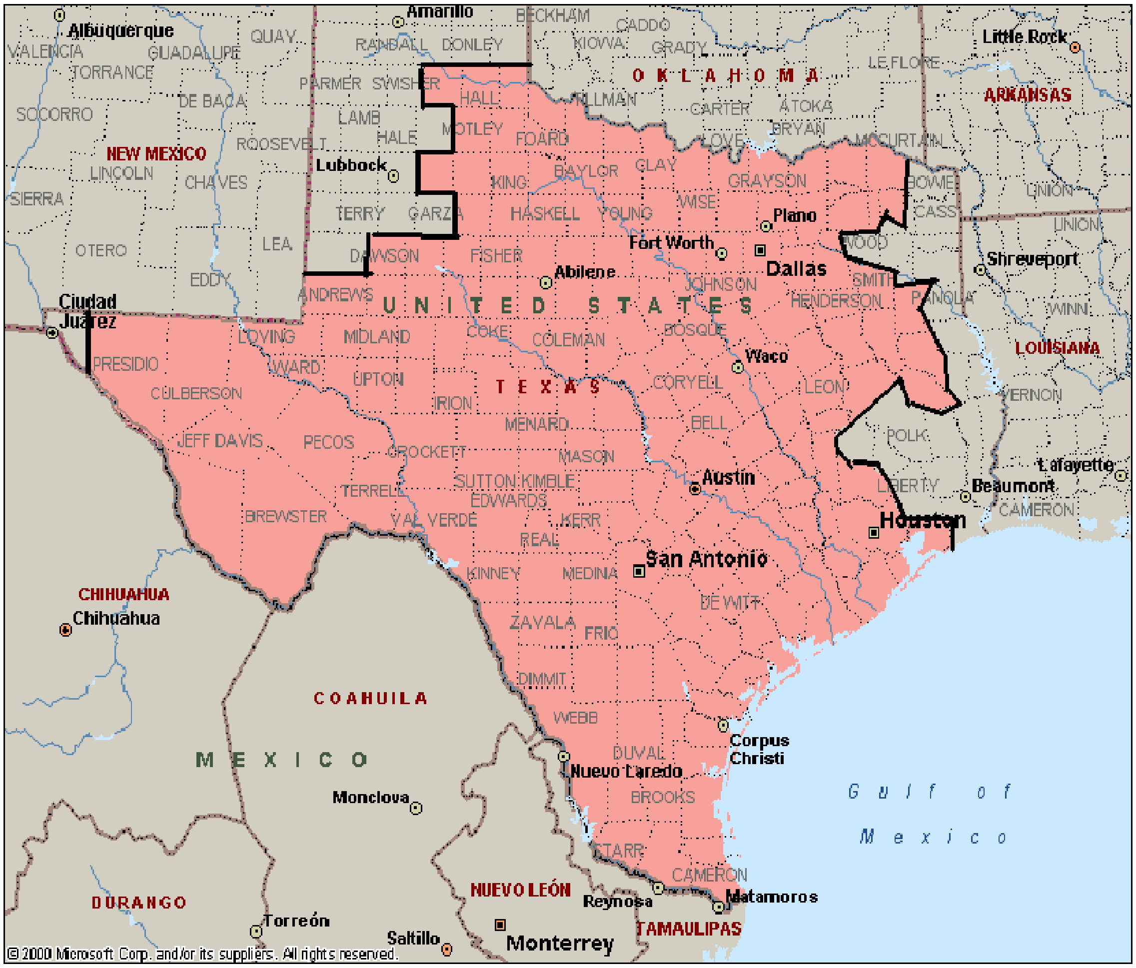

Figure 1 – ERCOT Regional Map

(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, this section shall be followed for all NOGRRs. ERCOT Members, Market Participants, PUCT Staff, ERCOT Staff, 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) All decisions of the Operations Working Group (OWG), as defined below, the Reliability and Operations Subcommittee (ROS), the ERCOT Technical Advisory Committee (TAC) and the ERCOT Board of Directors with respect to any NOGRR shall be posted to the Market Information System (MIS) Public Area within three Business Days of the date of the decision. All such postings shall be maintained on the MIS Public Area for at least 180 days from the date of posting.

(3) The "next regularly scheduled meeting" of the OWG, ROS, TAC, or ERCOT Board of Directors shall mean the next scheduled meeting for which required notice can be timely given regarding the item(s) to be addressed, as specified in the appropriate Board or committee procedures.

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

(5) ERCOT Staff may make corrections at any time during the processing of a particular NOGRR. Under certain circumstances, however, the Operating Guides can also be revised by ERCOT Staff rather than using the NOGRR process outlined in this section.

(a) This type of revision is referred to as an "Administrative NOGRR" or "Administrative Changes" and shall consist of 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 and Reliability Standards, 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 MIS Public Area and distribute the NOGRR to the OWG at least 5 Business Days before implementation. If no interested party submits comments to the Administrative NOGRR, ERCOT Staff shall implement it according to Section 1.3.6, Nodal Operating Guide Revision Implementation. If any interested party submits comments to the Administrative NOGRR, then it shall be processed in accordance with the NOGRR process outlined in this section.

1.3.2 Submission of a Nodal Operating Guide Revision Request

The following Entities may submit a NOGRR:

(1) Any Market Participant;

(2) Any Entity that is an ERCOT Member;

(3) PUCT Staff;

(4) ERCOT Staff; and

(5) Any other Entity who resides (or represent residents) in Texas or operates in the ERCOT Region.

1.3.3 Operations Working Group

(1) ROS shall assign a working group ("Operations Working Group" or “OWG”) to review and recommend action on formally submitted NOGRRs. ROS may create such a working group or assign the responsibility to an existing working group provided that:

(a) Such working group's meetings are open to ERCOT Staff, ERCOT Members, Market Participants, and the 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 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 shall be submitted by the chair or the chair’s designee on behalf of the 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 an ERCOT Protocol Revision Request (PRR) if such a change is necessary to accommodate a proposed NOGRR prior to proceeding with that NOGRR.

(4) ERCOT shall consult with the chair of the OWG to coordinate and establish the meeting schedule for the OWG or other assigned subcommittee. The OWG shall ensure that reasonable advance notice of each meeting, including the meeting agenda, is posted to the MIS Public Area.

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 MIS Public Area. 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;

(b) Reason for the suggested change;

(c) 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;

(d) NOGRR Impact Analysis (IA) (applicable only for a NOGRR submitted by ERCOT Staff);

(e) List of affected Operating Guide sections;

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

(g) 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 revision requested, a submitter must submit a completed version of the NOGRR with the deficiencies corrected.

(4) If a submitted NOGRR is complete or once a NOGRR is corrected, ERCOT shall post the complete NOGRR to the MIS Public Area and distribute the NOGRR to the OWG within three Business Days.

1.3.4.2 Withdrawal of a Nodal Operating Guide Revision Request

(1) By providing notice to OWG, the submitter of a NOGRR may withdraw the NOGRR at any time prior to its recommendation by the OWG. ERCOT shall post a notice of the submitter's withdrawal of a NOGRR on the MIS Public Area within one Business Day of the submitter's notice to OWG.

(2) The submitter of a NOGRR may request withdrawal of a NOGRR after its recommendation for approval by OWG. Such withdrawal must be approved by ROS (if it has not yet been considered by ROS) or by TAC (if it has been recommended for TAC approval by ROS but not yet considered by TAC).

(3) Once approved by TAC, a NOGRR cannot be withdrawn.

1.3.4.3 Operations Working Group Review and Action

(1) Any interested party may comment on the NOGRR.

(2) To receive consideration, comments must be delivered electronically to ERCOT in the designated format provided on the MIS Public Area 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 MIS Public Area—regardless of date of submission—shall be posted to the MIS Public Area and distributed electronically to the OWG within three Business Days of submittal.

(3) The OWG shall review the NOGRR at its next regularly scheduled meeting after the end of the 21 day comment period. At such meeting, the OWG may take action on the NOGRR to:

(a) Recommend approval as submitted or modified;

(b) If no consensus can be reached, present options for ROS consideration;

(c) Recommend rejection;

(d) Defer action on the NOGRR; or

(e) Request that ROS refer the NOGRR to a subcommittee, workgroup, or task force.

(4) Within three Business Days after OWG takes action (other than deferral), ERCOT shall issue a report ("OWG Recommendation Report") to ROS reflecting the OWG's action and post the same to the MIS Public Area. The OWG Recommendation Report shall contain the following items:

(a) Identification of submitter;

(b) Revised Operating Guide language;

(c) Identification of authorship of comments;

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

(e) Recommended action; and

1.3.4.4 Comments to the Operations Working Group Recommendation Report

(1) Any interested party may comment on the OWG Recommendation Report. To receive consideration, comments on the OWG Recommendation Report must be delivered electronically to ROS and ERCOT in the designated format provided on the MIS Public Area within 21 days from the date of posting/distribution of the OWG Recommendation Report. Comments submitted after 21 days may be considered at the discretion of ROS.

(2) Within three Business Days of receipt of comments related to the OWG Recommendation Report, ERCOT shall post such comments to the MIS Public Area. The comments shall include identification of the commenting Entity.

(3) Comments submitted in accordance with the instructions on the MIS Public Area—regardless of date of submission—shall be posted to the MIS Public Area and distributed electronically to the ROS and OWG within three Business Days of submittal.

(4) ROS shall review the OWG Recommendation Report and any posted comments to the Report at its next regularly scheduled meeting after the end of the 21 day comment period.

1.3.4.5 Nodal Operating Guide Revision Request Impact Analysis

(1) After the OWG's recommendation of approval of a NOGRR, and the issuance and posting of the OWG Recommendation Report, ERCOT shall prepare an IA based on the OWG Recommendation Report to identify and evaluate the required changes to ERCOT Systems and staffing needs, including ERCOT's operating systems, settlement systems, business functions, operating practices, ERCOT System operations, and staffing needs. If ERCOT has already prepared an IA, then ERCOT shall instead update the existing IA, if needed, to accommodate the OWG Recommendation Report.

(2) The IA shall include:

(a) An estimate of any cost and budgetary impacts;

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

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

(d) The identification of any manual workarounds that may be used as an interim solution.

1.3.4.6 Operations Working Group Review of Impact Analysis

(1) After ERCOT posts the results of the IA, OWG shall review the IA at its next regularly scheduled meeting. OWG may revise its OWG Recommendation Report after considering the information included in the IA.

(2) If OWG revises its Recommendation Report, a revised OWG Recommendation Report shall be issued by OWG to ROS and posted on the MIS Public Area. Additional comments received regarding the revised OWG Recommendation Report shall be accepted up to three Business Days prior to the ROS meeting at which the NOGRR is scheduled for consideration. If OWG revises its recommendation, ERCOT shall update the IA and issue the updated IA at least three Business Days prior to the regularly scheduled ROS meeting. If a longer review period is required for ERCOT Staff to update the IA, ERCOT Staff shall submit a schedule for completion of the IA to the ROS chair.

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 a OWG Recommendation Report has been posted and an IA based on such OWG recommendation (as updated if modified by OWG under Section 1.3.4.6, Operations Working Group Review of Impact Analysis) has been posted on the MIS Public Area for at least three days. The following information must be included for each NOGRR considered by ROS:

(a) The OWG Recommendation Report and IA; and

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

(2) ROS shall take one of the following actions regarding the OWG Recommendation Report:

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

(b) Reject the NOGRR; or

(c) Remand the NOGRR to the OWG with instructions.

(3) If ROS recommends approval of an NOGRR, ERCOT shall prepare a ROS Recommendation Report, issue the report to TAC and post the report on the MIS Public

Area within three Business Days of the ROS recommendation concerning the NOGRR. The ROS Recommendation Report shall contain the following items:

(a) Identification of the submitter of the NOGRR;

(b) Modified Operating Guide language proposed by ROS;

(c) Identification of the authorship of comments;

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

(e) OWG recommendation; and

(f) ROS recommendation.

1.3.4.8 ERCOT Impact Analysis Based on Reliability and Operations Subcommittee Recommendation Report

For NOGRRs not designated Urgent, ERCOT shall review the ROS Recommendation Report and update the IA as soon as practicable, but no later than 30 days after the ROS Recommendation Report is issued, unless a longer period is warranted due to the complexity of the changes proposed by ROS. ERCOT shall issue the updated IA (if any) to TAC and post it on the MIS Public Area within three Business Days of issuance. If a longer review period is required for ERCOT Staff to update the IA, ERCOT Staff shall submit a schedule for completion of the IA to the ROS and TAC chairs.

1.3.4.9 PRS Review of Project Prioritization

The PRS shall recommend to TAC an assignment of a Project Priority for each NOGRR recommended for approval by ROS that requires a change to ERCOT's computer systems.

1.3.4.10 Technical Advisory Committee Review and Action

(1) Upon recommendation for approval of a NOGRR by the ROS and issuance of an IA by ERCOT to TAC, TAC shall review the ROS Recommendation Report and the IA at its next regularly scheduled meeting; provided that the IA is available for distribution to the TAC at least seven days in advance of the TAC meeting.

(2) TAC shall take one of the following actions regarding the ROS Recommendation Report:

(a) Approve the ROS Recommendation Report as originally submitted or as modified by the ERCOT Board;

(b) Reject the ROS Recommendation Report; or

(c) Remand the ROS Recommendation Report to ROS with instructions.

(3) If the ROS Recommendation Report is approved by TAC, as recommended by ROS or modified by TAC, TAC shall review and approve or modify the proposed effective date.

(4) If TAC approves as submitted, approves as modified, or rejects a NOGRR, ERCOT shall prepare a TAC Action Report and post it on the MIS Public Area within three Business Days. The TAC Action Report shall contain the following items:

(a) Identification of the submitter of the NOGRR;

(b) Identification of the authorship of comments;

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

(d) Procedural history;

(e) ROS' recommendation;

(f) TAC Action (or recommendation to the Board for NOGRRs requiring changes to ERCOT's computer system);

(5) TAC shall consider the Project Priority of each NOGRR requiring a change to ERCOT's computer systems and make recommendations to the ERCOT Board.

(6) The Chair of TAC shall report the results of all votes by TAC related to Operating Guides revisions to the Board at its next regularly scheduled meeting.

1.3.4.11 ERCOT Board Review and Action

The ERCOT Board shall review all NOGRRs which impact ERCOT systems or staffing. The ERCOT Board shall take one of the following actions regarding NOGRRs recommended by TAC which have such impacts:

(a) Approve the TAC recommendation as originally submitted or as modified by the ERCOT Board; or

(b) Reject the TAC recommendation; or

(c) Remand the TAC recommendation to TAC with instructions.

1.3.4.12 Appeal of Decision

(1) With reference to a decision by OWG, any interested party may appeal directly to the ROS. Such appeal to the ROS must be submitted to ERCOT within ten Business Days after the date of the relevant decision. Appeals made after this time shall be rejected. Appeals to the ROS shall be posted on the MIS Public Area within three Business Days and placed on the agenda of the next available regularly scheduled ROS meeting, provided that the appeal is provided to ERCOT at least 11 days in advance of the ROS meeting; otherwise the appeal will be heard by the ROS at the next regularly scheduled ROS meeting.

(2) With reference to a decision by ROS, any interested party may appeal directly to the TAC. Such appeal to the TAC must be submitted to ERCOT within ten Business Days after the date of the relevant decision. Appeals made after this time shall be rejected. Appeals to the TAC shall be posted on the MIS Public Area within three Business Days and placed on the agenda of the next available regularly scheduled TAC meeting, provided that the appeal is provided to ERCOT at least 11 days in advance of the TAC meeting; otherwise the appeal will be heard by the TAC at the next regularly scheduled TAC meeting.

(3) With reference to a decision by TAC, any interested party may appeal directly to the ERCOT Board. Such appeal to the ERCOT Board must be submitted to ERCOT within ten Business Days after the date of the relevant decision. Appeals made after this time shall be rejected. Appeals to the ERCOT Board shall be posted on the MIS Public Area within three Business Days and placed on the agenda of the next available regularly scheduled ERCOT Board meeting, provided that the appeal is provided to the ERCOT General Counsel at least 11 days in advance of the Board meeting; otherwise the appeal will be heard by the Board at the next regularly scheduled Board meeting.

(4) Any interested party may appeal any decision of the ERCOT Board regarding the NOGRR to the PUCT or other Governmental Authority. Such appeal to the PUCT or other Governmental Authority must be made within 35 days of the date of the relevant decision. If the PUCT or other Governmental Authority rules on the NOGRR, ERCOT shall post the ruling on the MIS Public Area.

1.3.5 Urgent Requests

(1) The party submitting a NOGRR may request that the NOGRR be considered on an urgent basis. ROS may designate the NOGRR for urgent consideration. The OWG shall consider the Urgent NOGRR at its earliest regularly scheduled meeting, or at a special meeting called by the OWG chair.

(2) 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 TAC procedures. If approved, ERCOT shall submit a ROS Recommendation Report to the TAC 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.

(3) Notice of an urgent NOGRR pursuant to this section shall be posted on the MIS Public Area.

1.3.6 Nodal Operating Guide Revision Implementation

(1) For NOGRRs with no impact to ERCOT systems or staffing, upon TAC approval, ERCOT shall implement NOGRRs on the first day of the month following TAC approval, unless otherwise provided in the TAC Action Report for the approved NOGRR.

(2) For NOGRRs with impacts to ERCOT systems or staffing, upon Board approval, ERCOT shall implement NOGRRs on the first day of the month following Board approval, unless otherwise provided in the Board Action Report for the approved NOGRR.

(3) ERCOT shall implement an Administrative NOGRR on the first day of the month following the date it posted the Administrative NOGRR to the MIS Public Area.

1.4 Definitions

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

LINKS TO DEFINITIONS:

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

A

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Automatic Generation Control (AGC)
Application that receives signals from ERCOT for Regulation deployment and 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.

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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 Alert 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 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 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., Remedial Action Plans) 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;

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(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., Remedial Action Plans) 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 NERC Planning Standards and any subsequent revisions.

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

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Generator Reactive Power Sign/Direction Terminology

(1) Lagging power factor operating condition is when MVAR flow is out of the 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.

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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.

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Physical Responsive Capability (PRC)
A representation of the total amount of system wide online capability that has a high probability of being able to quickly respond to system disturbances. The PRC shall be calculated by (i) determining each Resource meeting the requirements of Section 2.3.1.2, Additional Operational Details for Responsive Reserve Providers, (ii) determining for each Resource the lesser quantity of the latest Net Dependable Capability, the Resource Plan HOL, or the telemetered real time capability, (iii) multiplying the lesser quantity of each Resource by the RDF, (iv) using that result to determine the amount of Responsive Reserve capability then available on each Resource, and (v) the sum, for all Resources, of the Responsive Reserve capability as determined for each Resource. The PRC shall be used by ERCOT to determine the appropriate Emergency Notification and EECP Steps.

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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 ROS.

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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 TSP or 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.

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1.5 Operational Training

1.5.1 System Operator Training Objectives

(1) Each operating Entity within the ERCOT System shall train its operators such that they will possess the necessary knowledge, skills and abilities to perform their assigned tasks in directing the operation of the 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

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. Qualified Scheduling Entity (QSE) operators who are responsible for providing base power schedules or Ancillary Services, Transmission Operators (TOs), and ERCOT System Operators shall have at least five days per year of training and drills on system emergencies. Training should use simulations appropriate to each class of operator and all such training shall meet or exceed established NERC Reliability Standards. Participation in 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 of the company, organization, Entity, or ERCOT Region. The ERCOT compliance template for the System Operator Training Program and a list of suggested training topics are available on the MIS Public Area.

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

September 1, 2008

(Effective Upon Texas Nodal Market Implementation)

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, Alerts 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 Emergency Electric Curtailment Plan (EECP) and other system events, and to ensure transaction schedules are simultaneous, all QSEs and TOs, and ERCOT will maintain their control system time within ±3 seconds of the National Bureau of

Standards (NBS) time signal. The NBS time signal shall set the time standard for ERCOT. ERCOT, QSEs and TOs are required to employ clocks, voice and data recording systems that synchronize automatically with the NBS on at least a weekly basis**.**

2.2.10 QSE/Resource Monitoring Program

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2.2.11 TSP Monitoring Program

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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
Regulation Down Service (Reg-Down) and Regulation Up Service (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 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 limit in response to a change in system frequency.
Responsive Reserve 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. Responsive Reserve 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 Emergency Electric Curtailment Plan (EECP) event.	Responsive Reserve 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 EECP or other emergencies.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Non-Spinning Reserve 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.	Direct the scheduling of Voltage Support Service 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 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 Service ***Reference: Protocol Section*** 3.14.1***, Reliability Must Run***	The provision of Generation Resource capacity and energy under a Reliability Must-Run (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

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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 (TSP), ERCOT will, prior to the peak each year, survey each Distribution Service Provider's (DSP) 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 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. Total 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 Step 4 of the Emergency Electric Curtailment Plan (EECP).

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

November 1, 2007

(Effective Upon Texas Nodal Market Implementation)

***** 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 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, Definitions and Acronyms.

(2) Each QSE shall provide ERCOT with a written back-up plan to continue operation in the event the QSE's scheduling center becomes inoperable.

(3) Each back-up 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 (MPs), 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 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 containing 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) for use 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) Tests to verify maximum lagging reactive capability shall be conducted during times when ERCOT System Loads are high, such as summer season afternoons when ambient temperatures exceed 90° F and when the ERCOT System Load is no less than 50,000 MW, but not necessarily at the time of system peak. Units being tested shall be operating at or above 95% of net dependable real power (MW) output.

(3) Tests to verify maximum leading reactive capability shall be conducted during times when ERCOT System Loads are low, such as off-peak hours during the spring season. Units being tested shall be operating at a real power (MW) output representative of its usual loading during such light Load periods.

(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 generator step-up 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 using the method specified in the form in Section 8, Attachment E, Biennial Unit Reactive Limits (Lead and Lag) Verification. Both high side and generator terminal values are required on the form for proper submittal of the test results.

(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 is at ERCOT's sole discretion, and any such waiver shall be effective for two years.

(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 on the form in Section 8, Attachment E, Biennial Unit Reactive Limits (Lead and Lag) Verification, 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 Entities 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 high and transmission system voltages are relatively low, i.e. summer season afternoons when ambient temperatures exceed 90° F and when the ERCOT System Load is less than 50,000 MW. 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.

(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 light and transmission system voltages are relatively high, i.e. off-peak hours during the spring season. 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 generator step up 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 using the method specified in the form located in Section 8, Attachment E, Biennial Unit Reactive Limits (Lead and Lag) Verification. 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 shall be submitted by the Resource Entity's QSE. The Resource Entity must properly complete all required data fields on the form in Section 8, Attachment E, Biennial Unit Reactive Limits (Lead and Lag) Verification, 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 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 3.10.7.4, 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 provide ERCOT with written back-up control plans to continue operation in the event the TOs control center becomes inoperable.

(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 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 20th 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 Total Transfer Capability (TTC) calculations, engineering studies, Real-Time security analyses, and operator actions.

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

(a) "Continuous Rating": Represents the continuous MVA rating of a Transmission Facility, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The Transmission Facility 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 Facility, including substation terminal equipment in series with a conductor or transformer, at the applicable ambient temperature. The Transmission Facility 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 Facility, 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 Continuous Rating. The Transmission Facility can operate at this rating for 15 minutes, assuming its pre-contingency loading was 90% of the Continuous 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 Continuous Rating.

(b) If a valid RAP is unavailable to unload the Transmission Facility post contingency or the pre-contingency loading is greater than 90% of the Continuous Rating, ERCOT shall enforce pre-contingency system operating limit(s) to control the post contingency loading of the Transmission Facility to levels below the Emergency Rating**.** The enforcement shall be implemented in a manner such that the post contingency loading will be at, or below, Continuous Rating within two hours.

(c) If a RAP is documented at ERCOT to relieve the loading on the Transmission Facility within 15 minutes; ERCOT shall enforce pre-contingency system operating limit(s) to control the post contingency loading of the Transmission Facility 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 Facilities to within Continuous Ratings as soon as practicable, based on Good Utility Practice.

ERCOT Nodal Operating Guides

Section 4: Emergency Operation

February 1, 2009

(Effective Upon Texas Nodal Market Implementation)

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

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, Alerts 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 Alert

(1) An Alert may be issued by ERCOT in accordance with Protocol Section 6.5.9.3.3, Alert, 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 (RAPs)), or mitigation plans, ERCOT shall issue an Alert. 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 Alert to all TOs and QSEs and shall post the message electronically to the MIS Secure Area. While operating under an Alert, 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 Alert, Emergency Electric Curtailment Plan (EECP) 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 Emergency Electric Curtailment Plan (EECP)

4.5.1 General

(1) At times it may be necessary to reduce electrical demand because of a temporary shortfall 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 procedure for curtailing demand during such emergencies, ERCOT has established this Emergency Electric Curtailment Plan (EECP) in accordance with Protocol Section 6.5.9.4, Emergency Electric Curtailment Plan.

(2) The objective of the EECP is to provide for maximum possible continuity of service while maintaining the integrity of the ERCOT Transmission Grid in order 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 EECP steps below, notifying all Qualified Scheduling Entities (QSEs) and Transmission Operators (TOs), and coordinating the implementation of the EECP conditions while maintaining transmission security limits. QSEs and TOs will notify all the Market Participants they represent of each declared EECP step.

(2) ERCOT has the authority to obtain emergency assistance energy over the Direct Current Tie(s) (DC Tie) for use by ERCOT. ERCOT is also the coordinating authority for requests for emergency type power into or out of ERCOT.

(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 steps in sequence. ERCOT can immediately implement Step 4 of the EECP any time the system frequency is below 59.8 Hz and will immediately implement Step 4 any time the frequency is below 59.5 Hz.

(5) Percentages for Step 4 Load shedding will be based on the previous year's TSP peak Load, as reported to ERCOT, and will be reviewed by ERCOT and modified annually.

(6) The ERCOT System Operator shall declare the EECP steps to be taken by QSEs and TSPs. QSEs and TSPs shall implement actions under that Step (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 step has been completed.

(7) During EECP Step 4, 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 EECP Operations

Prior to declaring EECP Step 1 detailed in Section 4.5.3.3, EECP Steps, ERCOT shall:

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

(2) Issue Dispatch Instructions to QSEs to suspend any ongoing ERCOT-required generating unit testing;

(3) Utilize Non-Spinning Reserve (Non-Spin) services that can be deployed to increase Responsive Reserves; and

(4) ERCOT shall use the Reserve Discount Factor (RDF) for the purpose of monitoring Physical Responsive Capability (PRC). The PRC will be used by ERCOT to determine the appropriate emergency notification and EECP steps.

4.5.3.2 General Procedures During EECP Operations

ERCOT Control Area Authority will re-emphasize the following operational practices during EECP 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 EECP Step;

(3) QSEs and TOs shall notify each represented Market Participant of declared EECP Step;

(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 EECP steps 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 EECP operations.

4.5.3.3 EECP Steps

(1) **Step 1 – Maintain ERCOT Physical Responsive Capability (PRC) on units plus RRS MW provided from Load Resources Equal To 2300 Mw**

(a) ERCOT shall:

(i) Utilize available DC Tie capability that is not already being used by the market;

(ii) Notify the Southwest Power Pool Security Coordinator;

(iii) Issue OOM dispatch instructions to uncommitted units available within the expected timeframe of the emergency.

(iv) Use available BtB import capacity that is not already being used and inquire about availability of Block Load Transfers (BLT).

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

(2) **Step 2 – Maintain ERCOT Physical Responsive Capability (PRC) on units plus RRS MW provided from Load Resources equal to 1750 MW**

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

(i) Instruct TSPs to reduce Customer Loads by using distribution voltage reduction measures, if deemed beneficial by the TSP;

(ii) Instruct QSEs to deploy all Responsive Reserve (RRS), which is supplied from Load Resources (controlled by high-set under-frequency relays); and

(iii) With approval of the affected non-ERCOT control area, may instruct TSPs to implement BLTs, which transfer Load from the ERCOT Control Area to non-ERCOT Control Areas.

(3) **Step 3 – Maintain System frequency at 60 Hz**

(a) In addition to measures under Steps 1 and 2, ERCOT shall deploy all available EILS Resources as a single block via a single Verbal Dispatch Instruction to all QSEs providing EILS.

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

(4) **Step 4 - Maintain System frequency at 59.8 Hz or greater**

(a) In addition to measures under Steps 1, 2, and 3, ERCOT shall direct all TSPs and their agents to shed firm Load, in 100 MW blocks, distributed as agreed and documented in the ERCOT operating procedures in order to maintain a steady state system frequency of 59.8 Hz. ERCOT may take this action prior to the expiration of the ten minute EILS Resource deployment period if ERCOT, in its sole discretion, believes that shedding firm Load is necessary to maintain the stability of the ERCOT System. If, due to ERCOT System conditions, EILS Resources are not deployed prior to this action, ERCOT shall deploy EILS Resources as soon as possible following this action.

(b) In addition to measures under Steps 1 and 2, TSPs shall, 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 shall not manually drop Load connected to under-frequency relays during the implementation of the EECP;

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	2006 Total Transmission Operator Load (MW)
American Electric Power	9.27
Austin Energy	3.89
Brazos Electric Power Cooperative	4.12
CenterPoint Energy	24.34
City of Bryan	0.54
City of College Station	0.29
City of Denton	0.50
City of Garland	0.95
CPS Energy	7.22
Lower Colorado River Authority	5.19
Magic Valley Electric Cooperative	0.56
Public Utility Board of Brownsville	0.40
Rayburn Country Electric Cooperative	0.99
South Texas Electric Coop-Medina Electric Coop	0.65
Texas New Mexico Power	2.28
Tex-La	0.15
Oncor	38.66
ERCOT Total	**100.00**

4.5.3.5 EECP Termination

(1) ERCOT shall:

(a) Continue EECP 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 steps in reverse order, where practical;

(d) Notify each QSE and TO of EECP Step 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 EECP steps are released in accordance with these Operating Guides;

(b) Notify represented Market Participants of EECP step changes;

(c) Report back to the ERCOT System Operator when each step 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 Texas Nodal Market Implementation)

***** 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

November 1, 2007

(Effective Upon Texas Nodal Market Implementation)

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

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 DC 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 IEEE/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 "Type 1 SPS" is any SPS that has wide-area impact and specifically includes any SPS that:

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

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

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:

(a) 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;

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

(c) 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;

(d) The status indication of any automatic or manual arming of the SPS shall be provided as SCADA alarm inputs to the owners of any facility(ies) controlled by the SPS; and

(e) When a Transmission Service Provider (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. 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.

(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 ERCOT Market Information System (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 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 (MPs)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.

(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 Network Operations Model Change Request, 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 Texas Nodal Market Implementation)

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

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.

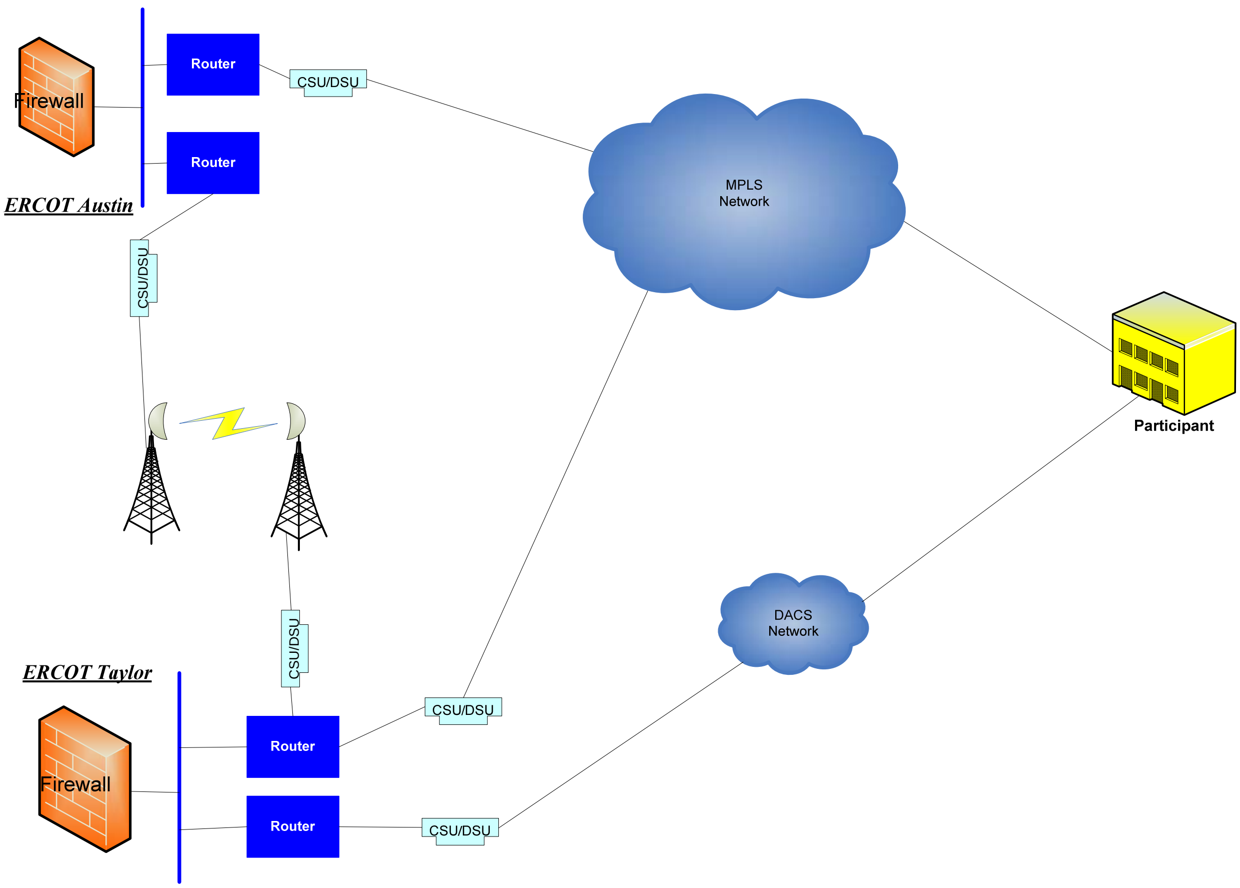


Figure 1 ERCOT Wide Area Network Overview

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 Texas Nodal Market Implementation)

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

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

November 1, 2007

(Effective Upon Texas Nodal Market Implementation)

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

Relay Misoperation Report

DATE:	TIME:	UTILITY:	VOLTAGE:
RELAY TYPE: STYLE #:	CB NUMBER:	LINE/BUS/AUTO/UNIT NAME:	
FLAGS:	MANUFACTURER:		

Description of Misoperation/Failure:

(80 Character)

Investigation Results:

(80 Character)

Corrective Action:

(80 Character)

Target Date:	

Recommendations:

Reported By:			Date:
Phone Number:			

ERCOT Nodal Operating Guides
Section 8
Attachment C

Turbine Governor Speed Tests

November 1, 2007

(Effective Upon Texas Nodal Market Implementation)

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

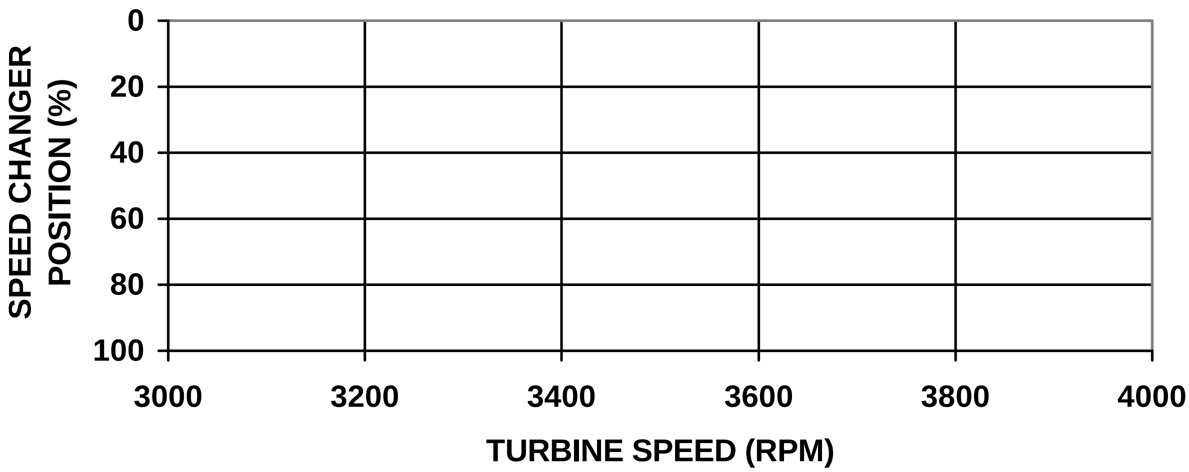
$$Rs = \frac{(E - F) \times 100}{3600}$$

[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

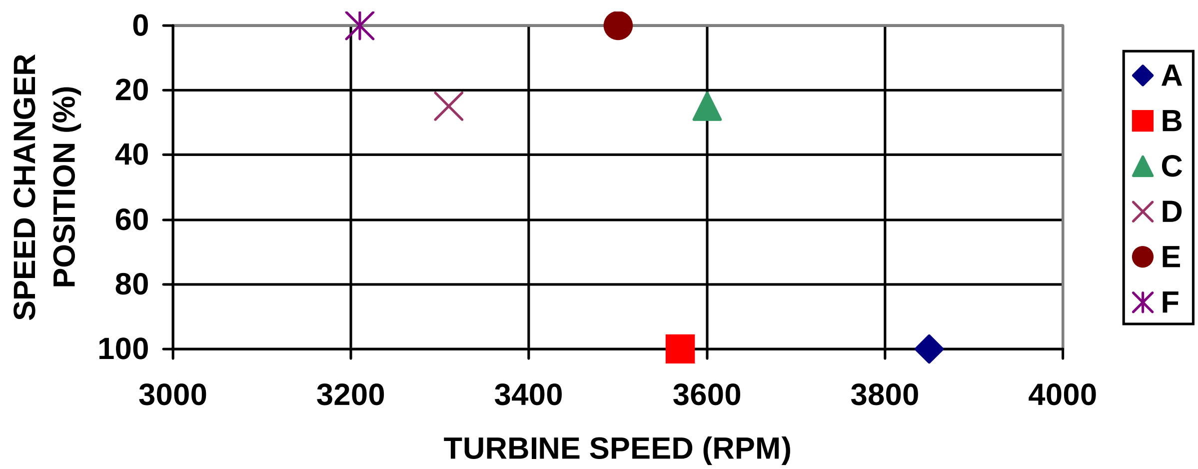
$$Rs = \frac{(E - F)\times 100}{3600} = \frac{(3500 - 3210)\times 100}{3600} = 8.06\%$$

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

(b) Set load reference at minimum value.

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

(d) Reduce speed until valve demand just reaches maximum value.
Record valve demand as value 'B' (in %) and speed as value 'C' (in RPM).

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

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

(g) Increase speed until valve demand just reaches minimum value.
Record valve demand as value 'E' (in %) and speed as value 'F' (in RPM).

Turbine Governor Speed Regulation Test Results

	A	B	C	D	E	F
VALVE DEMAND (%)						
Speed (rpm)						

Speed Regulation With Decreasing Speed

$$R_D = \frac{100}{(B - A)} \times \frac{(3600 - C)}{3600} \times 100$$

Speed Regulation With Increasing Speed

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

Comments: ____

____

____

____

____

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 Texas Nodal Market Implementation)

***** 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

Biennial Unit Reactive Limits (Lead and Lag) Verification

November 1, 2007

(Effective Upon Texas Nodal Market Implementation)

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

BIENNIAL UNIT REACTIVE LIMITS (LEAD AND LAG) VERIFICATION

GENERAL INFORMATION

Unit Code (16 character): *______________Location (County): *________________________________

Unit Name: *________________________Date of test: *________________________

Generator's QSE: *____________________Resource Entity: *_____________________

For test details, reference Section 3.3.2.2, Non-Coordinated Reactive Testing and 3.3.2.3, Coordinated Reactive Testing.

* This entry is required for all tests

*CORRECTED UNIT REACTIVE LIMIT (CURL) CURVE: (1)
Maximum Lagging Reactive at current Gross Dependable MW Output ______ MVAR(Gross) at ____ MW(Gross) (1)
Maximum Lagging Reactive at current Gross Low Sustained Limit MW Output ______ MVAR(Gross) at ____ MW(Gross) (1)

Maximum Leading Reactive at current Gross Dependable MW Output ______ MVAR(Gross) at ____ MW (Gross) (1)
Maximum Leading Reactive at current Gross Low Sustained Limit MW Output _______ MVAR(Gross) at ____ MW(Gross) (1)

* Defined Test:
❑ Coordinated Test
❑ Non-Coordinated Test

*Test Performed:
❑ Maximum Leading Reactive
❑ Maximum Lagging Reactive
❑ Other (specify location): ________________________________

*Location at which data observed (specify all that apply):
❑ Generator Terminals (preferred)
❑ High Voltage side of Generator Step-Up (GSU) Transformer

TESTED REACTIVE CAPABILITY
*Generator Gross Reactive (MVAR): (+/-) _____ (2)
*Auxiliary Reactive Load (MVAR): _____ (3) ❑ Observed ❑ Calculated
*Net Reactive to the Transmission System (MVAR): (+/-) _____ (5) ❑ Observed ❑ Calculated
*Net Generator Reactive (MVAR): _______ (6) ❑ Observed ❑ Calculated

TEST CONDITIONS:

*Start Time: ________________ *Stop Time: ______________
*Generator Gross Generation (MW): _____ (7)
*Net Dependable Unit Generation (MW): _____ (8)
*Auxiliary Load (MW): _____ (4) *Generator Terminal Power Factor: _____
*Transmission Bus Voltage (kV): _____ (9) *Nominal Transmission Bus Voltage (kV): _____
*Generator Terminal Voltage (kV): _____ Auxiliary Bus Voltage (kV): _____ (10)
Ambient Air Temperature (°F): _____ (10)
*Generator Hydrogen Pressure, if applicable (psig): _____ (11)
*Generator Step Up transformer tap setting: _____Ratio: HV _____kV/ LV ______kV (12)
*Abnormal Conditions at Time of Test: (13)____
____
____
____
____

***Briefly describe factors that limited reactive capability during test:**

- ❑ Maximum Generator Voltage with Auxiliary loads
- ❑ Maximum Generator Voltage without Auxiliary loads
- ❑ Minimum Generator Voltage with Auxiliary loads
- ❑ Minimum Generator Voltage without Auxiliary loads
- ❑ Main transformer capability plus Auxiliary loads
- ❑ Steady State Stability Limit
- ❑ Maximum Gross MW capability
- ❑ Minimum Gross MW capability
- ❑ Minimum Excitation Limiter
- ❑ Loss of Field Relay
- ❑ Other: ____

____
____

SUBMITTAL

*Resource Entity Representative: ____

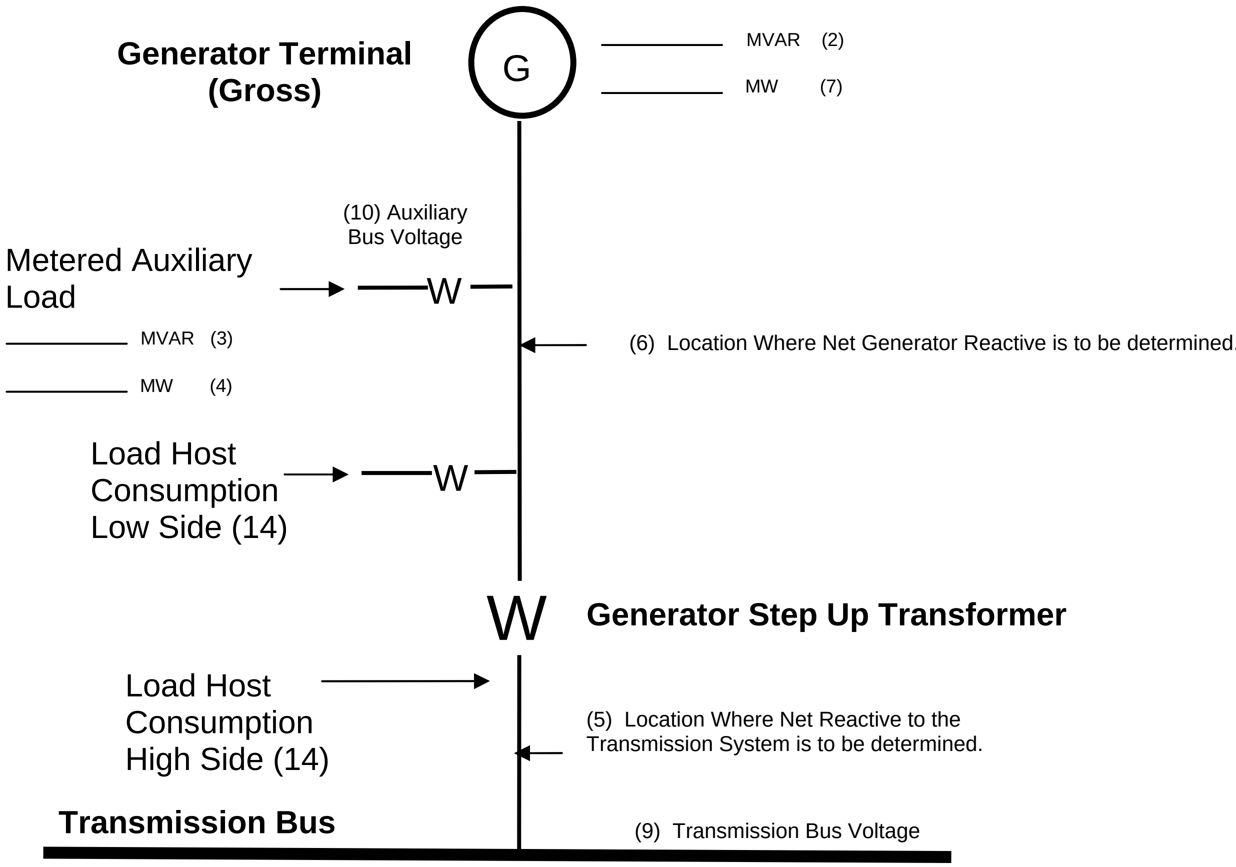
*QSE Representative: ____

*QSE/Resource Entity Contact Phone Number: _________________________________

Email Address:____

*Date submitted to ERCOT Rep.: ____

Notes: Maximum Leading and Maximum Lagging tests may be conducted at different times of the year.



NOTES

(1) These quantities are taken directly from the Corrected Machine Capability Curve. The MVAR reactive maximum lagging value is the expected output at the generator terminal (gross output) with the generating unit at the Gross Dependable MW Output. This is the Gross equivalent of the Net Dependable Output. The MVAR reactive maximum leading value is the expected output at the generator terminal (gross output) with the generating unit at the Gross Low Sustained Limit MW output. This is the Gross equivalent of the Net Low Sustained Limit. The Maximum Lagging Reactive at current Gross Low Sustained Limit and Maximum Leading Reactive at current Gross Low Sustained Limit are used for curve validation only.

(2) Metered reactive at the generator's terminals.

(3) Auxiliary Reactive Load (Load only associated with Generator such as fans, boiler pumps etc.).

(4) Metered Auxiliary Real Load (Load only associated with Generator).

(5) **Observed** – metered reactive on the high side of the generator step up transformer to the transmission system (Show leading reactive value as a negative (-) number).

Calculated - (+/-) metered reactive at the generator's terminals minus metered Auxiliary

Reactive consumption minus generator step up transformer reactive losses minus Load host reactive consumption (Load host does not apply to most generators but only pertains to generators with self serve load).

(6) **Observed** - (+/-) as metered, Gross generator reactive minus metered Auxiliary Reactive consumption (Show leading reactive value as a negative (-) number).
Calculated - (+/-) metered net reactive to the transmission system minus generator step up transformer reactive losses minus Load host reactive consumption (Load host does not apply to most generators but only pertains to generators with self serve load),

(7) Metered at the generator terminals.

(8) Most current tested value on record at ERCOT,

(9) Required for Coordinated Test.

(10) (if limiting).

(11) PSIG can be determined from PSIA by subtracting 14.7 from the PSIA gauge reading.

(12) Actual tap setting – not nominal tap setting.

(13) Describe fully.

(14) Load Host consumption exists on either the low side or the high side of the step up transformer but typically not both.

ERCOT Nodal Operating Guides
Section 8
Attachment F

Seasonal Hydro Responsive Reserve Net Capability Verification

November 1, 2007

(Effective Upon Texas Nodal Market Implementation)

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

November 1, 2007

(Effective Upon Texas Nodal Market Implementation)

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 8.1.2.2, 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

November 1, 2007

(Effective Upon Texas Nodal Market Implementation)

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

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.

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

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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

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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

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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